04

BUILDING VALUE

CANADIAN OIL SANDS TRUST ANNUAL REPORT 2004

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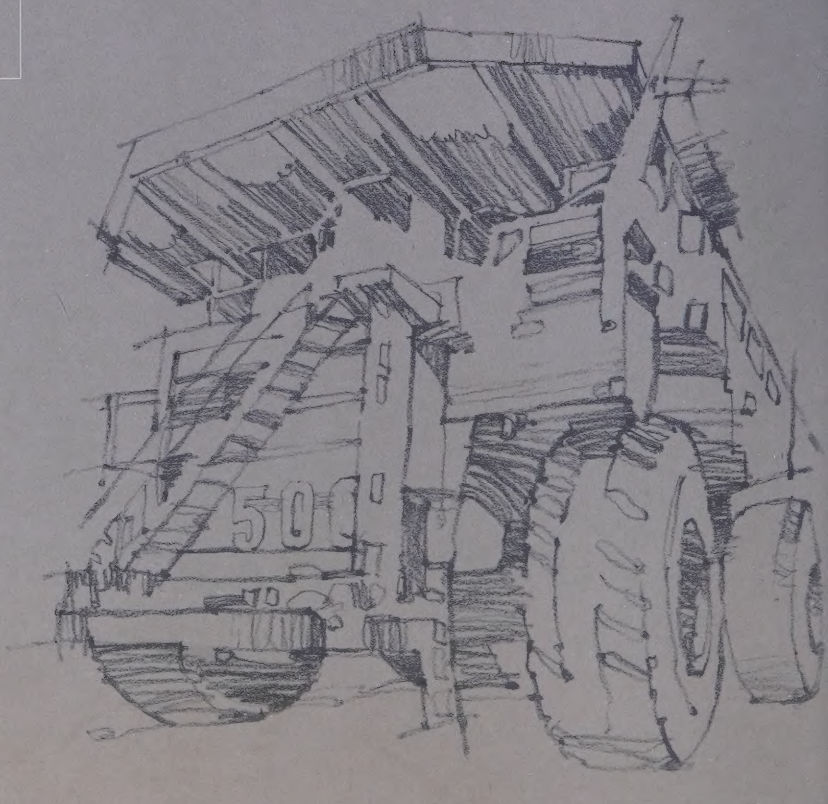


COS.UN

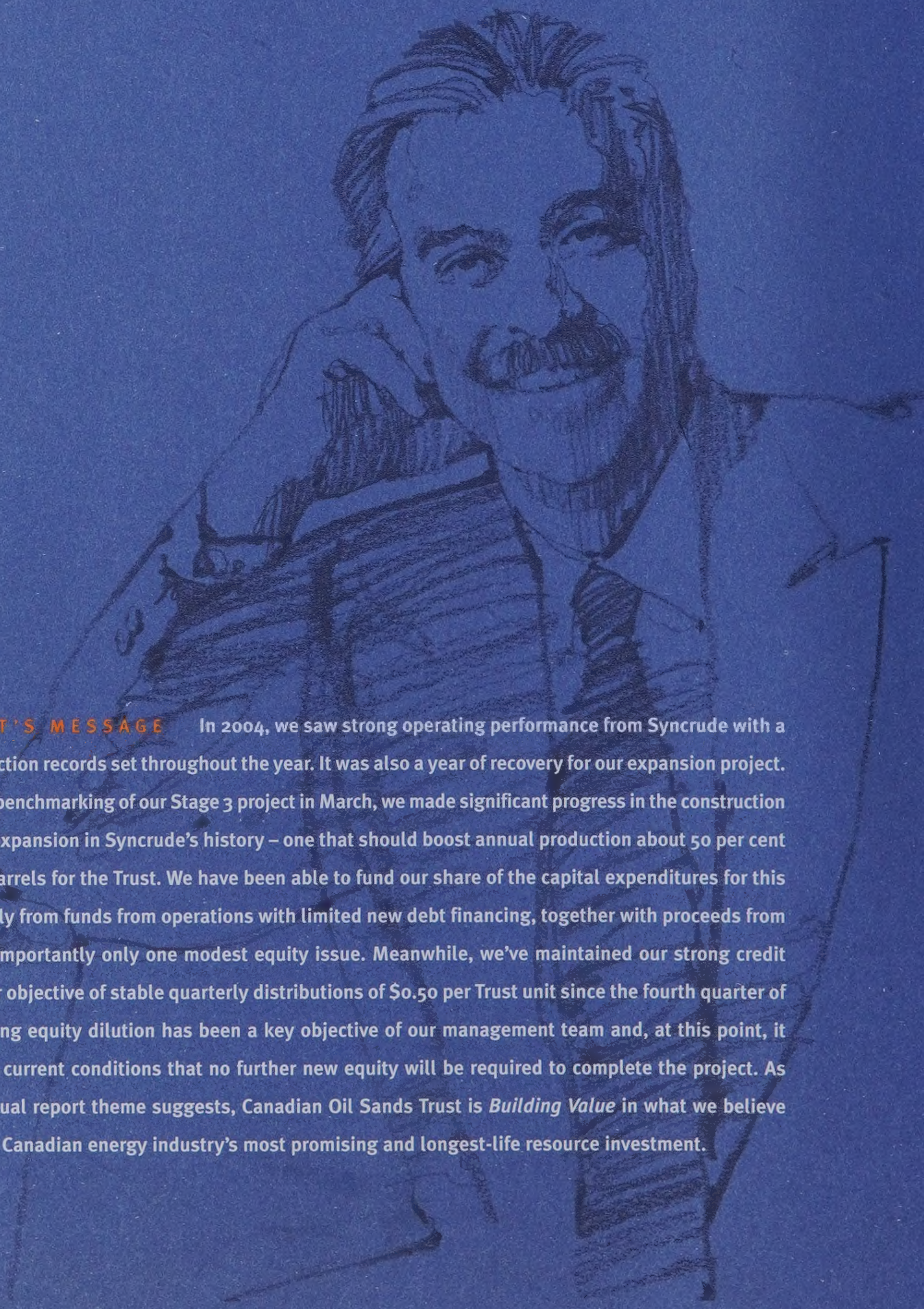
2004

PROFILE With our 35.49 per cent working interest in the Syncrude project, Canadian Oil Sands Trust provides a pure play opportunity in the Alberta oil sands. We have a 35-year proven reserve life and are currently expanding operations with an anticipated 50 per cent growth in productive capacity of light, sweet crude oil by mid-2006.

An open-ended investment trust, Canadian Oil Sands trades on the Toronto Stock Exchange under the symbol COS.UN.

HIGHLIGHTS

	2004	2003	% change
Financial ($ millions, except per Trust unit amounts)			
Revenues, after transportation and marketing expense	**1,352**	932	45
Per Trust unit	**15.18**	11.70	30
Net income	**509**	310	64
Per Trust unit (basic and diluted)	**5.72**	3.89	47
Funds from operations	**576**	273	111
Per Trust unit	**6.47**	3.43	89
Unitholder distributions	**180**	170	6
Per Trust unit	**2.00**	2.00	–
Weighted-average Trust units (millions)	**89.0**	79.7	12
Operations			
Syncrude Sweet Blend sales volumes			
Total (MMbbls)	**31.0**	24.4	27
Daily average (bbls)	**84,575**	66,793	27
Operating costs ($/bbl)	**19.40**	21.12	(8)
Capital expenditures ($ millions)	**942**	786	20
Average selling price ($/bbl, after hedging)	**43.68**	38.23	14
West Texas Intermediate ($US/bbl)	**41.47**	30.99	34
Average foreign exchange rate ($US/$Cdn)	**0.77**	0.71	8



PRESIDENT'S MESSAGE In 2004, we saw strong operating performance from Syncrude with a string of production records set throughout the year. It was also a year of recovery for our expansion project. Following a re-benchmarking of our Stage 3 project in March, we made significant progress in the construction of the largest expansion in Syncrude's history – one that should boost annual production about 50 per cent to 45 million barrels for the Trust. We have been able to fund our share of the capital expenditures for this project primarily from funds from operations with limited new debt financing, together with proceeds from our DRIP and importantly only one modest equity issue. Meanwhile, we've maintained our strong credit ratings and our objective of stable quarterly distributions of $0.50 per Trust unit since the fourth quarter of 2001. Minimizing equity dilution has been a key objective of our management team and, at this point, it appears under current conditions that no further new equity will be required to complete the project. As this year's annual report theme suggests, Canadian Oil Sands Trust is *Building Value* in what we believe represents the Canadian energy industry's most promising and longest-life resource investment.

Strong Operations at Syncrude

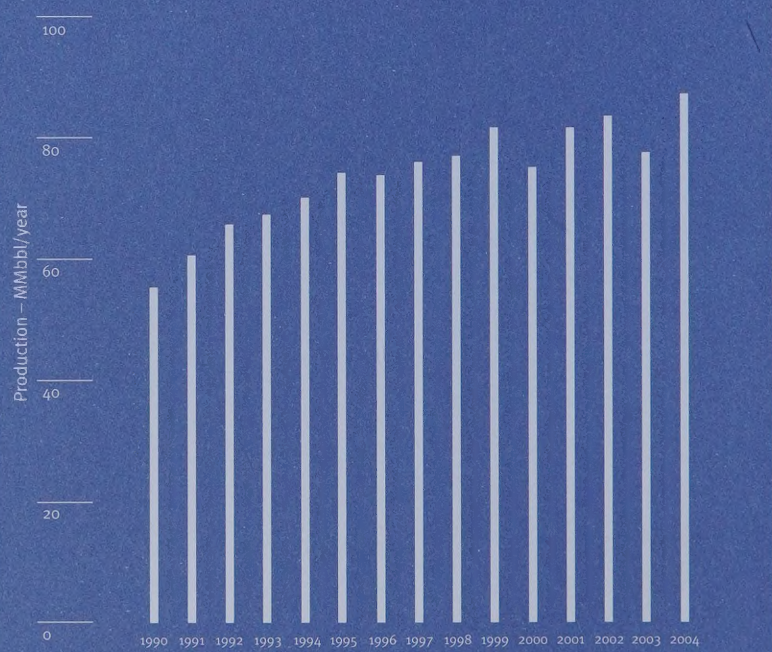
After an exceptional first quarter in 2004, Syncrude followed up with relatively stable operations through the remainder of the year, turning in record-setting production of 87.2 million barrels of Syncrude Sweet Blend crude oil, equivalent to 31 million barrels net to the Trust. This performance reflects the upper end of the production forecast we set at the beginning of the year. The absence of a coker turnaround last year helped push production to these record levels. Meanwhile, operating costs at $19.40 per barrel were down from 2003 but greater than budgeted due primarily to higher natural gas prices, which accompanied higher crude prices. Our only major operational setbacks for the year were the 10-week extension of the scheduled maintenance required for our LC-Finer, one of our major bitumen conversion units, and an electrical interruption which caused the LC-Finer to be down for another five weeks starting in mid-December.

As a result of strong operations at Syncrude, combined with robust crude oil prices, Canadian Oil Sands delivered outstanding financial results in 2004. Funds from operations were an unprecedented $6.47 per unit, almost double from 2003, while net income increased to $5.72 per unit. These excellent results enabled us to maintain our annual $2.00 distribution per Trust unit and end the year with a stronger than anticipated balance sheet against capital expenditures which approached $1 billion in 2004.

For 2005, we are anticipating Canadian Oil Sands production of 28-31 million barrels net to the Trust. The upper end of this forecast reflects strong operational performance and the planned coker 8-2 turnaround in the first quarter, while the lower end of the range incorporates the possibility of a second coker turnaround late in the year. Canadian Oil Sands has budgeted an average operating cost of $15.51 per barrel, plus energy expenses of $5.21 per barrel. We anticipate the price of crude oil will remain strong in 2005, and forecast an average West Texas Intermediate price of US$40 per barrel and a Canadian dollar of US$0.80.

Building Value

Syncrude Production Performance



Syncrude turned in record-setting production in 2004, at 87.2 million barrels (31 million barrels net to the Trust). Significant growth in production is expected once the Stage 3 expansion is completed in mid-2006.

Stage 3 Expansion Recovers

Earlier in 2004, we announced that our Stage 3 expansion project had exceeded its projected cost and schedule, with costs expected to be $7.8 billion, or $2.8 billion to the Trust, and completion targeting mid-2006. To help steward the project to a successful completion, a number of initiatives were implemented in March and April of 2004, such as restructuring the project into smaller sub-projects and reorganizing the management team, with Syncrude and owner personnel in key positions rather than contractors. I am pleased to report that since March 2004 we've made significant strides, with about 75 per cent of construction now complete, putting us slightly ahead of our revised schedule and within our revised project cost estimate. We expect that the majority of the mechanical work will be completed by late 2005, with commissioning of the new Upgrader to follow in early 2006.

The magnitude and complexity of the Stage 3 project are unparalleled in this industry, as were the challenges we faced in building the Upgrader within a live operating plant. Although the project has not been completed, more than 80 per cent of our anticipated Stage 3 expenditures are now behind us as of February 21, 2005 and, as a result, I believe most of the construction risks have diminished. I am optimistic that we will successfully complete the project as planned and achieve our Stage 3 objectives of expanded production and lower unit operating costs.

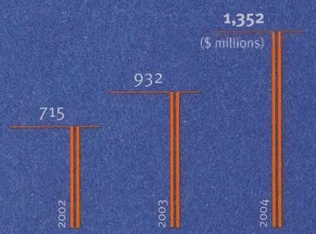
In addition to meeting the goals for the Stage 3 expansion, Canadian Oil Sands remains committed to the following corporate objectives:

- provide Unitholders with optimal returns by preserving investment grade credit ratings, minimizing equity dilution and growing our stable distributions;
- pursue accretive acquisition opportunities of oil sands assets;
- become the lowest cost bitumen producer in the industry; and
- maintain one of the lowest overhead cost structures in the sector.

Core Value

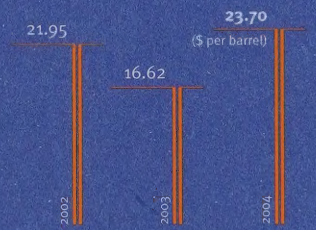
Revenues

After Transportation, Marketing Expense and Hedging



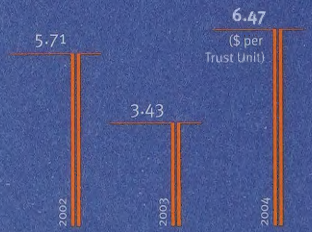
Netback

After Hedging

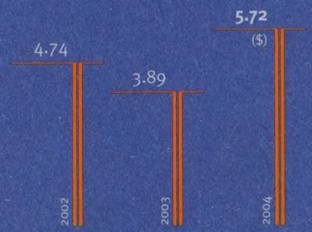


For further information, see Statistical Summary on page 76.

Funds from Operations



Net Income Per Trust Unit



Net revenues, net income, funds from operations and netback were all higher in 2004, largely due to higher crude oil prices and increased production volumes at Syncrude.

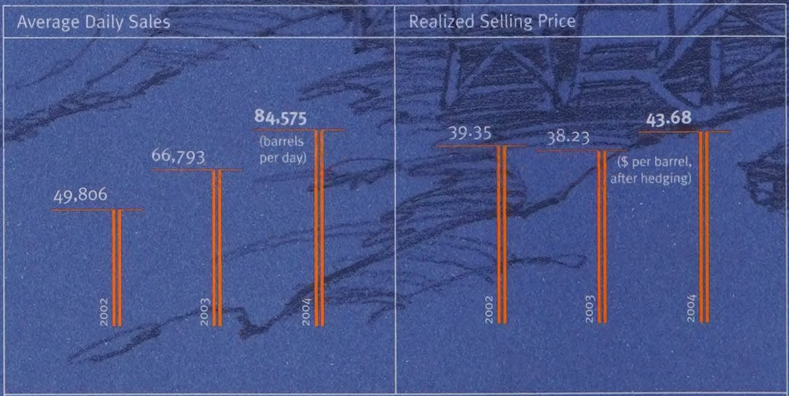
At the end of 2004, our net debt totalled approximately $1.7 billion, representing about 39 per cent of total book capitalization, which is actually better than last year. Given our commodity price outlook, we expect our net debt to capitalization ratio to remain relatively flat throughout 2005, and our credit strength should improve as we near the end of the Stage 3 expansion. At that time, our primary focus will be to repay some of the construction debt incurred for the project, which is key to establishing higher, stable distributions. We appreciate our Unitholders' patient support for the last three years as we held the line on distributions, while reinvesting most of our cash flow into Stage 3. I believe this strategy continues to be a main driver behind the appreciation in our unit price.

One of several benchmarking metrics that we follow is to compare our total annual return to our Unitholders to those of two other oil sands mining companies and two market indices. While industry comparisons are never perfect, we have performed well against these benchmarks in recent years. Here is how we measured up, specifically in 2004, compared to 2003:

Benchmarks	Total Shareholder Return	
	2004	2003
Suncor Energy	31%	33%
Western Oil Sands	42%	22%
S&P/TSX Capped Energy Trust Index	30%	46%
S&P/TSX Oil and Gas Exploration and Production Index	41%	19%
COS	**54%**	**27%**

Foreign Ownership

In the 2004 budget, the federal government proposed legislation that all mutual trust funds, including resource trusts, could not have more than 50 per cent foreign ownership. Canadian Oil Sands believes this legislation is harmful to the long-term prosperity of the Canadian economy. Last year, we worked vigorously with industry and government groups to explore ways in which Canadians can realize the greatest potential



The increase in 2004 sales volumes reflects stronger production at Syncrude and the Trust's higher ownership interest. The increase in the average U.S. dollar WTI price, partially offset by hedging losses and a stronger Canadian dollar, resulted in a higher 2004 realized selling price.

from domestic and foreign investment. We believe that applying the 15 per cent withholding tax to all distributions of non-resident investors and removing any limitation on foreign ownership is a better approach for the federal government to take. Only through open and unrestricted access to the world capital markets can income trusts, like Canadian Oil Sands, realize their greatest potential. This is also true of the economic health of Canada which, along with its residents, derives great benefits from foreign investment.

Environmental Performance

Environmental responsibility remains a cornerstone of Syncrude's commitment to sustainable development. In November, Syncrude received regulatory approval from Alberta Environment and the Alberta Energy and Utilities Board for its previously announced sulphur dioxide emissions reduction project. Requiring an investment of more than $400 million by Syncrude, the project involves retrofitting a flue gas scrubbing system onto Syncrude's two existing cokers, and is designed to reduce total SO_2 emissions by 2008 to about 60 per cent of currently approved levels. Other emissions, such as particulate matter and metals, also are expected to be reduced by around 50 per cent. Additional information regarding Syncrude's environmental and community initiatives are provided in Syncrude's comprehensive Sustainability Report, a copy of which is available from the Trust or Syncrude.

In November 2004, Russia ratified the Kyoto Protocol, which commits 55 industrialized nations, including Canada, to reduce carbon dioxide emissions by 2012. On February 15, 2005 the Protocol came into effect in Canada. In 2003, the federal government introduced a number of measures and commitments to help reduce the uncertainty of implementing this Protocol. That enabled us to estimate the upper range of the cost impact to Syncrude to be approximately 20 to 30 cents per barrel, assuming no improvement in emission reduction. Over the past decade, Syncrude has succeeded in reducing its greenhouse gas emissions and intends to further reduce its CO_2 emissions in the next 10 years. Therefore, we should be able to reduce the financial impact of the Kyoto Protocol.

Pure Value

Data prior to 2001 merger represent Athabasca Oil Sands Trust, the surviving entity.

Canadian Oil Sands has provided a strong return to Unitholders since inception. The unit price has increased to $67.61 from $10.00 per Trust unit at the initial public offering and distributions totalled $16.16 per Trust unit at the end of 2004. The average Unitholder return since inception is approximately 26 per cent per year.

Continuing to Build Value

During 2005, we will move into the final phase of construction of the Stage 3 expansion project, a major milestone for Syncrude. Following the scheduled maintenance turnaround of Coker 8-2 undertaken early this year, we expect that operating reliability at our mines and upgrader will remain strong. Finally, we believe that crude oil markets, although volatile, will remain robust throughout the year, with prices ranging between US$35-$45 and unpredictable world events likely causing prices to rise rather than fall. Most large reservoirs around the world have reached their peak production capacity and are now in decline. Against this backdrop, it is becoming progressively more challenging to increase global oil production to meet continually growing demand, particularly from Asia. For this reason, we see sustainable robust pricing for our product, albeit with continued volatility, as we go forward.

Canadian Oil Sands thus enters 2005 unhedged, with full exposure to crude oil prices. In the past few years, we have hedged up to half of our production to protect the downside of our cash flow capacity as part of the Stage 3 financing plan. However, the current strength of our balance sheet and the near completion of our Stage 3 expansion now allows us to be unhedged, which is the Trust's policy for periods of lower capital intensity.

In closing, Canadian Oil Sands truly is *Building Value* – for today and well into the future. We have an exceptionally long life asset and we very soon will experience an unprecedented growth in production which should fuel continued outstanding returns to our Unitholders under current market conditions. I look forward to another successful year in 2005, with the help of our staff, our board and Syncrude's entire personnel, and I thank you for your continued support.

Marcel R. Coutu
President and Chief Executive Officer

February 21, 2005

MD&A

ADVISORY – in the interest of providing the Canadian Oil Sands Trust ("Canadian Oil Sands", the "Trust", "we" or "us") Unitholders and potential investors with information regarding the Trust, including management's assessment of the Trust's future production and cost estimates, plans and operations, certain statements throughout this MD&A contain "forward-looking statements" under applicable securities law. Forward-looking statements in this M&DA include, but are not limited to, statements with respect to: the amount of reserves recoverable and the estimate of reserves, the anticipated completion and cost of the UE-1 construction; the anticipated benefits of Stage 3; the expected results obtained from Stages 4 and 5 and the timeframe of their commencement; the expected royalty payments in 2005 and beyond; the expected depreciation and depletion rate for 2005; the estimated construction completed at year-end 2004 as compared to the final construction at the end of the project; the placement of hedges whether for crude oil or natural gas in 2005 and beyond; the expected production level at Syncrude for 2005; the expected timing and associated production impact of coker turnarounds, the expected level of oil and natural gas prices for 2005; the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange and operating costs have on the Trust's funds from operations and net income; the expected capital expenditures in 2005; future reductions in SO_2 emissions; the anticipated levels of foreign ownership; the anticipated impact of having income trusts in the S&P/TSX Composite Index; and the anticipated taxability of distributions paid by the Trust. You are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Trust believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: the supply and demand metrics for oil and natural gas; the ability of the other joint venture owners of Syncrude to modify the 2005 budget at Syncrude; the uncertainty of labour supply and cost, normal risks associated with litigation, general economic, business and market conditions; regulatory changes; and such other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by the Trust. You are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and the Trust does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

MD&A

MANAGEMENT'S DISCUSSION AND ANALYSIS

BUSINESS DESCRIPTION

Canadian Oil Sands Trust is an open-ended investment trust that generates income from its oil sands investment in the Syncrude Joint Venture ("Syncrude"). The Trust's 35.49 per cent Syncrude ownership is the largest interest and the only pure investment in the joint venture.

Syncrude has been in operation for more than 25 years and has a proved and probable reserve base of approximately five billion barrels, or 1.8 billion barrels net to the Trust, that should allow it to continue producing at current annual rates of 83 million barrels for approximately another 60 years. Syncrude is operated and administered by Syncrude Canada Ltd. ("Syncrude Canada") on behalf of eight joint venture owners, two of whom are subsidiaries of the Trust. It operates the largest oil sands facility in the world and produces crude oil through the mining of oil sands from ore deposits in the Athabasca region of Northern Alberta. Currently, Syncrude operates in its Base, North and Aurora North mines, which represent its proved reserves of approximately three billion barrels, or one billion barrels net to the Trust. An additional lease, which has not yet been developed and is referred to as Aurora South, represents substantially all of Syncrude's probable reserves. Syncrude's total resource base is nine billion barrels which also encompasses other leases.

In addition to operating large oil sands mines, Syncrude operates bitumen extraction plants and an upgrading complex that processes bitumen into a light sweet crude oil. Syncrude's trademark product is a high quality, light, sweet synthetic blend, referred to as "Syncrude Sweet Blend" ("SSB")™, which has an average gravity of about 32° API and less than 0.2 per cent sulphur content. Each joint venture owner receives its share of SSB production in kind and is responsible for its own marketing activities. SSB is transported by pipeline to refineries throughout Canada and the United States ("U.S.").

EXECUTIVE OVERVIEW

While Syncrude Canada is responsible for the daily operations of the joint venture, there are various sub-committees of Syncrude Canada's Board of Directors which are staffed by the joint venture owners. Officers of Canadian Oil Sands Limited ("COSL"), the Trust's operating subsidiary which manages its 35.49 per cent interest in Syncrude, participate in the governance of Syncrude's operations and expansion plans through key roles on the Syncrude Canada Board and the Management Committee of Syncrude. In particular, officers of COSL chair Syncrude Canada's Board of Directors, the Audit and Pension Committee and the CEO Committee, as well as the Management Committee.

Canadian Oil Sands is responsible for financing its share of Syncrude's operations and its own administrative costs. Sources of financing include funds generated from the sale of its SSB production and, as required, debt and equity financing.

Our funds generated from operations are highly dependent on the net selling prices received for our SSB, production volumes, and the operating costs of producing SSB. We have contracted out the marketing of our share of Syncrude volumes to EnCana Corporation ("EnCana"), which markets

these volumes to refineries in Canada and the U.S. for a fee. The prices we receive for our SSB product correlate closely to U.S. West Texas Intermediate ("WTI") oil prices, and are also impacted by movements in U.S./Canadian foreign exchange rates. Crude oil prices can be volatile, reflecting world events and supply and demand fundamentals. During the past three years, WTI prices have fluctuated from a low of US$18 per barrel in 2002 to a high of US$55 per barrel in 2004.

Production volumes reflect the capacity of the Syncrude facility and reliability of operations. A proved plus probable reserve life estimated at over 60 years, provides a secure, reliable source of bitumen for the production of SSB. The process of mining, extracting and upgrading bitumen is a highly technical and complex manufacturing operation that requires regular maintenance of the various operating units, which can affect production volumes, and consequently, revenues. Production volumes have a significant impact on per barrel operating costs as a large proportion of the costs are fixed and if the plant is not operating, repair costs typically are also being incurred. The most significant variable production cost is natural gas; accordingly, operating costs are also sensitive to changes in natural gas prices. On a per barrel of SSB basis, the current operations consume approximately 0.7 mcf for each barrel of SSB produced.

In addition to funding sustaining capital expenditures, our funds generated from operations are used to repay debt, pay distributions to our Unitholders and to partially finance our share of Syncrude's expansion projects. The Trust makes distributions to its Unitholders after it receives trust royalties, distributions and interest payments from its subsidiaries.

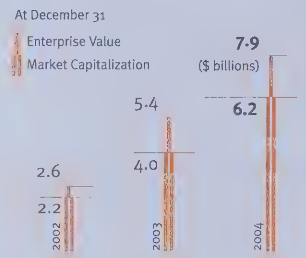
To develop its extensive mineable oil sands leases, Syncrude has designed a five-stage expansion plan aimed at achieving sustainable production capacity in excess of 500,000 barrels per day of sweet synthetic crude oil. Syncrude has current capacity to produce approximately 240,000 barrels per day, or 85,000 barrels per day net to the Trust. Stages 1 and 2 have been completed and Syncrude is in the process of completing Stage 3. After mid-2006 when it is anticipated to be completed, Stage 3, combined with current reliability initiatives, is expected to:

- provide a 50 per cent increase in production to approximately 350,000 barrels per day;
- lower operating costs per barrel as a result of scale economies and the use of cost-saving technologies;
- produce a higher quality product known as Syncrude Sweet Premium ("SSP")™ which we anticipate will attract a higher price than SSB; and
- improve environmental performance, including a reduction in SO_2 and CO_2 emissions for every barrel of crude oil produced.

The total Stage 3 cost is estimated at $7.8 billion, or $2.8 billion net to the Trust, of which $6.3 billion, or approximately $2.3 billion net to the Trust, has been expended as of December 31, 2004. Stage 4 of the plan will debottleneck the current expansion following its completion and is expected to be substantially less capital intensive than Stage 3. Stage 5 should commence within the next decade and is currently envisioned as additional mining trains and a fourth coker similar to Stage 3. Neither Stage 4 nor Stage 5 have received owner approval and are preliminary designs at this time.

MARKET CAPITALIZATION AND ENTERPRISE VALUE

The capital appreciation of our Trust units and the issuance of additional debt and equity for Stage 3 resulted in further growth in market capitalization and enterprise value. The Trust remains the largest energy trust in Canada.



At December 31, 2004 based on the closing market price of $67.61 per Trust unit ("Unit"), our market capitalization and enterprise value was approximately $6.2 billion and $7.9 billion, respectively, up from $4.0 billion and $5.4 billion, respectively, at December 31, 2003 based on a closing Unit price of $45.69.

We intend to pursue accretive acquisition opportunities of oil sands assets to augment Syncrude's internal growth plans. We also seek to optimize long-term Unitholder value through stable and increasing distributions. Distributions are dependent upon cash generated, which is highly sensitive to crude oil prices, production and sales volumes, and operating costs; financing requirements for capital expansions; and our objective of maintaining an investment grade credit rating. We feel it is necessary to maintain a conservative capital structure and a strong credit rating in order to participate in, and finance, future expansion and acquisition opportunities with minimal equity dilution.

More information regarding Canadian Oil Sands, including our Annual Information Form, is available on SEDAR at www.sedar.com.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except per Trust unit amounts)	**2004**	2003	2002
Revenues, after transportation and marketing expense	**1,352**	932	715
Net income	**509**	310	271
Net income per Trust unit, Basic and Diluted	**5.72**	3.89	4.74
Total assets	**5,068**	4,260	1,852
Long-term debt	**1,700**	1,437	622
Total other long-term financial liabilities [1]	**136**	132	68
Unitholder distributions per Trust unit	**2.00**	2.00	2.00
Funds from operations	**576**	273	326
Funds from operations per Trust unit	**6.47**	3.43	5.71

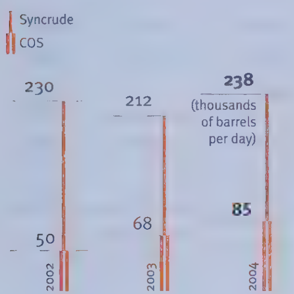
[1] Includes employee future benefits and other liabilities as well as the asset retirement obligation.

Throughout 2004, we owned a 35.49 per cent working interest in Syncrude. As a result of having acquired from EnCana a 10 per cent Syncrude working interest in February 2003 and another 3.75 per cent working interest in July 2003, our 2003 operating results reflect an average working interest ownership in Syncrude of 31.92 per cent, compared with 21.74 per cent in 2002.

Revenues, after transportation and marketing expense include sales of SSB, crude oil and foreign currency hedging gains and losses less transportation and marketing expenses. We reported higher net revenues in 2004 compared to both 2003 and 2002 as a result of an increase in sales volumes and a higher realized selling price, which was somewhat offset by a stronger Canadian dollar relative to the U.S. currency. Our sales volumes, which differ from our share of Syncrude's production volumes primarily as a result of in-transit pipeline volumes, averaged 84,575 barrels per day in 2004, which was an increase of 27 per cent and 70 per cent, respectively, compared to 2003 and 2002. In 2004, Syncrude set a production record by producing 87.2 million barrels, which surpassed production in its previous best year in 2002 by 3.4 million barrels. Production

DAILY PRODUCTION

Syncrude production increased in 2004 as a result of no coker turnarounds and stronger operations in the first half of the year.



in 2003 amounted to 77.3 million barrels which was significantly lower than 2004 primarily due to two coker turnarounds in that year, as well as unscheduled and extended scheduled maintenance, while there were no coker turnarounds in 2004. In addition to the higher Syncrude production volumes in 2004 compared to each of 2003 and 2002, Canadian Oil Sands' larger working interest ownership in the year contributed to the increase in volumes.

In 2004, we realized a net selling price after hedging of $43.68 per barrel, a per barrel increase of $5.45 and $4.33 over the price we earned in each of 2003 and 2002, respectively. The increase reflects the substantial increase in U.S. WTI prices, which averaged US$41.47 per barrel, US$30.99 per barrel, and US$26.18 per barrel in each of 2004, 2003 and 2002, respectively. The increase in the benchmark crude price was somewhat offset by the strengthening of the Canadian dollar against the U.S. dollar in 2004 and 2003, as well as Canadian Oil Sands realizing a weaker price differential relative to Canadian dollar WTI on our realized selling price.

The increase in our net revenues, combined with the improvement in current and future income tax amounts, resulted in higher net income and net income per Unit in 2004. These improvements more than offset the increase to all other expenses and the lower foreign exchange gains compared to each of 2003 and 2002. Each of these factors, excluding the non-cash components of future income tax recoveries, depreciation, depletion and accretion ("DD&A") expense and unrealized foreign exchange gains, resulted in improved funds from operations in total and on a per Unit basis in 2004 compared to each of 2003 and 2002.

In 2003, while net income was higher than in 2002 due to higher foreign exchange gains on our U.S. dollar denominated debt, the operational difficulties combined with an increased number of Units outstanding, resulted in lower net income per Unit. Funds from operations were lower in 2003 compared to 2002 primarily as a result of lower production and an increase in operating costs, non-production costs, net interest expense and income and Large Corporations tax expense, offset partially by the increase in net revenues.

Total assets continued to increase significantly in 2004 compared to 2003 as Stage 3 construction advanced. Our share of Syncrude's capital expenditures, largely related to the Stage 3 capital program, increased capital assets in 2004 by approximately $0.9 billion and by $0.8 billion in 2003. Total assets grew substantially in 2003 as a result of acquiring the additional 13.75 per cent working interest, which increased capital assets by $1.9 billion.

Long-term debt at December 31, 2004 was higher than at December 31 in each of 2003 and 2002, reflecting the additional debt issued in 2004 to fund our share of Syncrude's capital expenditure program. Long-term debt increased substantially in 2003 compared to 2002 due to the assumption of $0.5 billion of debt to finance the $1.5 billion purchase of the 13.75 per cent working interest and another $0.4 billion related to the funding required for our share of the Stage 3 capital program.

The other long-term financial liabilities increased only slightly in 2004 from 2003, but doubled from 2002 as a result of assuming the Syncrude Canada employee future benefits liability and asset retirement obligation associated with the 13.75 working interest in Syncrude acquired in 2003.

SUMMARY OF QUARTERLY RESULTS

($ millions, except per Trust unit amounts)	2004				
	Q1	Q2	Q3	Q4	Annual
Revenues, after transportation and marketing expense	**318.5**	**340.8**	**359.3**	**333.4**	**1,352.0**
Net income	**103.4**	**98.0**	**185.7**	**122.1**	**509.2**
Net income per Trust unit, Basic and Diluted	**1.18**	**1.12**	**2.06**	**1.34**	**5.72**
Funds from operations	**141.8**	**155.0**	**157.4**	**121.6**	**575.8**
Funds from operations per Trust unit	**1.62**	**1.77**	**1.75**	**1.33**	**6.47**

	2003				
	Q1	Q2	Q3	Q4	Annual
Revenues, after transportation and marketing expense	176.3	232.9	300.4	222.4	932.0
Net income	83.5	63.7	106.0	56.9	310.1
Net income per Trust unit, Basic and Diluted	1.28	0.80	1.23	0.65	3.89
Funds from operations	51.5	56.3	120.3	44.7	272.8
Funds from operations per Trust unit	0.79	0.71	1.39	0.51	3.43

Quarterly results, with the exception of net income per Unit in the first quarter, improved in 2004 compared to 2003 as a result of several factors applicable in each quarter. As there were no coker turnarounds in 2004 but two turnarounds in the prior year, Syncrude production was significantly higher in 2004. Production averaged approximately 238,000 barrels per day in 2004, compared to approximately 212,000 barrels per day in 2003. Also, Canadian Oil Sands' larger working interest in 2004 contributed to increased volumes compared to 2003. Thirdly, the realized selling price after hedging was significantly higher in the second, third and fourth quarter of 2004 compared to the similar periods in 2003. In the first quarter, while U.S. WTI prices were slightly higher in 2004 compared to 2003, a significantly stronger Canadian dollar and a weaker price differential relative to Canadian dollar WTI more than offset the price increase, resulting in a lower realized selling price per barrel.

The improved quarterly results in 2004 associated with the increased Syncrude production, larger working interest ownership, and a higher realized selling price were somewhat offset by the increase in operating costs, non-production costs, Crown royalties, net interest expense, DD&A expense and lower foreign exchange gains, all of which impacted net income. The increase in operating, non-production, and DD&A expense are a result of a larger working interest in 2004 compared to 2003. Financing costs increased in 2004 due to the higher debt levels required to fund our share of Syncrude's capital expenditure program. Funds from operations were also impacted by those same items, excluding DD&A and unrealized foreign exchange gains as they are non-cash amounts.

In the first quarter of 2004, while total net income was higher than the same period in 2003 due to the increased working interest, net income per Unit was lower. The reduction in first quarter

per Unit results reflects a $56 million decrease to earnings attributable to the $12 million foreign exchange loss in 2004 compared to the $44 million foreign exchange gain in 2003, combined with significantly more Units outstanding. The average Units outstanding in the first quarter of 2003 reflected the issue of 21.7 million Units on February 28, 2003 for a total of 65.5 million Units compared to the same quarter of 2004 which had 87.3 million Units outstanding.

Material variances in financial results between 2004 and 2003 are explained further in the following sections of this MD&A. Canadian Oil Sands considers material information to be any information relating to the business of the Trust and its subsidiaries that would reasonably be expected to have a significant influence on a reasonable investor's investment decision. We believe users of our financial results consider critical information to be that which explains the Trust's funds from operations, after capital expenditures, which is available for distribution to Unitholders, for reinvestment in growth through expansions or acquisitions, or for repayment of debt. We endeavour to identify and provide in our MD&A, financial statements, and guidance documents on a timely basis and in an understandable form the parameters that impact our funds from operations, namely crude oil prices, production volumes, our price relative to WTI prices, hedging impacts, costs of operations, financing costs, capital and other relevant costs.

REVIEW OF CONSOLIDATED RESULTS

Canadian Oil Sands reported record results in 2004, outperforming prior years based on net income and funds from operations, in total and per Unit for both measures. Net income in 2004 was $509 million, or $5.72 per Unit, which was an increase of $199 million, or $1.83 per Unit, compared to the prior year. Funds from operations increased 111 per cent to $576 million, or $6.47 per Unit in 2004 from 2003. Both net income and funds from operations improved year-over-year as a result of increased Syncrude production volumes, a larger Syncrude working interest, and a higher realized selling price. These improvements to net income in 2004 were offset somewhat by increases in expenses and the lower foreign exchange gains, as shown in the table below on a per barrel basis. Funds from operations also were impacted by the same factors, excluding DD&A and unrealized foreign exchange gains as they are not cash items.

($/barrel)	2004	2003	$ Change
Average realized selling price, after hedging	**43.68**	38.23	5.45
Operating costs	**(19.40)**	(21.12)	1.72
Crown royalties	**(0.58)**	(0.49)	(0.09)
Netback	**23.70**	16.62	7.08
Non-production cost	**(1.55)**	(1.57)	0.02
Administration and insurance	**(0.58)**	(0.67)	0.09
Interest, net	**(3.08)**	(2.78)	(0.30)
Depletion, depreciation and accretion	**(5.55)**	(3.80)	(1.75)
Foreign exchange gain	**2.57**	5.54	(2.97)
Current and future income tax	**0.94**	(0.62)	1.56
	(7.25)	(3.90)	(3.35)
Net income per barrel	**16.45**	12.72	3.73

Net income before unrealized foreign exchange gains and future income tax recoveries, which management believes is a better measure of operational performance than net income, was $393 million, or $4.41 per Unit, an improvement of $232 million, or $2.39 per Unit compared to the prior year.

($ millions)	2004	2003	Change
Net income per GAAP	**509.2**	310.1	199.1
Deduct:			
Foreign exchange gain on long-term debt	**(89.2)**	(147.2)	58.0
Future income tax recovery	**(27.3)**	(2.2)	(25.1)
Net income before foreign exchange and future income taxes	**392.7**	160.7	232.0

The earnings reflected in the previous table are a measurement that is not defined by Canadian generally accepted accounting principles ("GAAP"). The Trust also reports funds from operations and Unitholder distributions on a total and per Unit basis, which are measures that do not have any standardized meaning under GAAP. Funds from operations are calculated from the Trust's cash flow statement as cash from operating activities before changes in working capital. In management's opinion, it is a key performance indicator of the Trust's ability to generate cash to finance its operations and pay distributions. The earnings in the previous table, the Trust's funds from operations, and Unitholder distributions may not be directly comparable to similar measures presented by other companies or trusts.

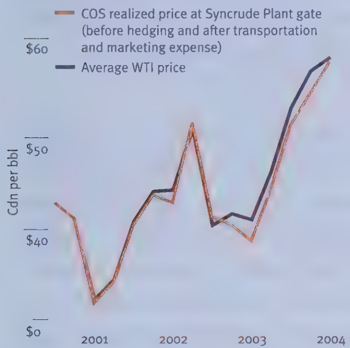
Revenues, after Transportation and Marketing Expense

($ millions)	2004	2003	$ Change	% Change
Sales revenue	**1,658.2**	1,064.1	594.1	56
Transportation and marketing expense	**(44.9)**	(35.8)	(9.1)	25
	1,613.3	1,028.3	585.0	57
Crude oil hedging gains (losses)	**(274.3)**	(99.9)	(174.4)	175
Currency hedging gains (losses)	**13.0**	3.6	9.4	261
Total hedging gains (losses)	**(261.3)**	(96.3)	(165.0)	171
Revenues, after transportation and marketing expense	**1,352.0**	932.0	420.0	45
Sales volumes (MMbbls)	**31.0**	24.4	6.6	27

($ per barrel)	2004	2003	$ Change	% Change
Sales revenue	**53.57**	43.65	9.92	23
Transportation and marketing expense	**(1.45)**	(1.47)	0.02	(1)
Realized selling price before hedging losses	**52.12**	42.18	9.94	24
Crude oil hedging gains (losses)	**(8.86)**	(4.10)	(4.76)	116
Currency hedging gains (losses)	**0.42**	0.15	0.27	180
Total hedging gains (losses)	**(8.44)**	(3.95)	(4.49)	114
Total realized selling price	**43.68**	38.23	5.45	14

REALIZED PRICE DIFFERENTIAL TO WTI

Volatility in the price differentials between SSB and benchmark crude oil prices has increased over the past two years.



Sales revenue reflects sales volumes and prices at the point of delivery. Revenue after deducting transportation and marketing fees reflects the realized selling price at the Syncrude plant gate.

Revenues after transportation and marketing expense and before hedging were $1.6 billion in 2004, an increase of $0.6 billion compared to the same period in 2003. The significant improvement in 2004 compared to 2003 is primarily a result of higher crude prices and sales volumes, which averaged approximately 85,000 barrels per day in 2004, an improvement of 27 per cent compared to 2003. The increase in sales volumes in 2004 resulted both from record production volumes at Syncrude and the Trust's larger ownership of Syncrude.

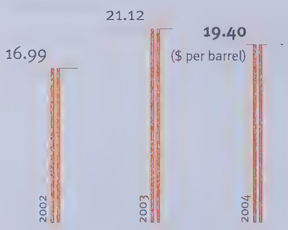
The Trust's realized selling price before hedging for 2004 averaged $52.12 per barrel, or $9.94 per barrel higher than the average price in 2003. WTI prices averaged US$41.47 per barrel in 2004, compared to US$30.99 per barrel in the same period of 2003. Partially offsetting the increase of U.S. dollar WTI prices in 2004 was a stronger Canadian dollar that averaged $0.77 US/Cdn compared to $0.71 US/Cdn in 2003, and a weaker price differential to Canadian dollar WTI in 2004 compared to the prior year.

In 2004, our SSB product traded at a weighted-average discount of $1.53 per barrel relative to Canadian dollar average WTI prices compared to a weighted-average discount of $0.67 per barrel realized in 2003. The change in the differential primarily reflects a shift in the supply and demand fundamentals in 2004 from 2003. The first half of 2003 was prior to additional synthetic crude oil volumes coming into the market from other oil sands projects and supply was short therefore, our SSB product traded at an average premium of $1.00 per barrel to Canadian dollar WTI prices. During the latter half of 2003 and into the first quarter of 2004, we believe that the market needed to absorb the additional volumes that had entered the market, which resulted in Canadian Oil Sands' realizing a discount on our selling prices relative to Canadian dollar WTI that ranged from $0.91 per barrel up to $2.88 per barrel. The price differential strengthened again in March and April of 2004 as supply was constrained due to turnarounds at various oil sands projects and demand improved for diluent products. However, differentials widened out after the first quarter and were at discounts to WTI until the fourth quarter of 2004 when a series of supply problems resulted in an improved selling price for our SSB product. The fluctuations in the price differentials over the past two years reflect a substantial increase in the volatility of crude oil price and SSB differentials relative to benchmark prices.

The results of our crude oil and foreign exchange hedges in total reduced our net revenues in 2004 by $261 million, or $8.44 per barrel, compared to a decrease of net revenues of $96 million, or $3.95 per barrel, in 2003. Total net revenues in 2004 were $1.4 billion, which surpassed our original budget by $0.4 billion and was in line with our revised guidance issued on October 22, 2004. The better than originally anticipated results were attributable to a significant improvement in U.S. WTI prices that averaged US$41.47 per barrel, over $16 per barrel higher than our original budget of US$25 per barrel, somewhat offset by a stronger Canadian dollar relative to our budgeted foreign exchange rate. We had hedged approximately 45 per cent of our crude oil sales, which mitigated the increase of actual crude oil prices relative to budgeted prices. Also, higher Syncrude

OPERATING COSTS

Stronger operations in the first half of 2004 and no coker turnarounds resulted in a 13 per cent increase in Syncrude production, which lowered per barrel operating costs compared to 2003.



production volumes of 87.2 million barrels, compared to budgeted volumes of 86 million barrels, contributed to higher actual net revenues.

At February 21, 2005 based on current expectations and the strength of the Trust's balance sheet, we do not have any crude oil hedges in place. The financial results of our crude oil and foreign currency hedges are more fully discussed in the Risk Management section of the MD&A.

Operating Costs

Total operating costs in 2004 increased by approximately $86 million compared to 2003, of which almost $60 million related to the Trust's larger working interest in 2004 and $15 million related to the changes in the Trust's product and linefill inventory. In 2003, our operating costs were reduced by $6 million as a result of gains on natural gas hedging, of which there were no hedges in place for 2004. Syncrude's total operating costs in 2004, despite a 13 per cent increase in production, were virtually unchanged from 2003 as the significant coker turnaround costs in 2003 were comparable to the LC-Finer turnaround and maintenance costs, higher purchased energy, and increased variable compensation expenses in 2004.

The substantial increase in the Trust's share of Syncrude's production volumes as a result of no coker turnarounds in the year more than offset the increase in the Trust's operating costs, thereby reducing the per barrel operating cost to $19.40 per barrel, from $21.12 per barrel in the prior year.

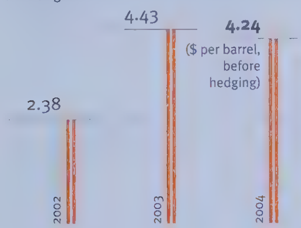
Natural gas costs at $6.28 per gigajoule ("GJ") were the same in each of 2004 and 2003, but consumption increased substantially in 2004 compared to 2003 as a result of increased production. The increase in consumption volumes in 2004 was somewhat offset by the coker turnaround impacts in 2003 which resulted in increased volume purchases. Natural gas is a significant component of the bitumen production and upgrading processes.

Syncrude produced approximately 13 per cent more SSB in 2004, averaging 238,000 barrels per day, compared to 2003, in which year production averaged 212,000 barrels per day. The record production was due to no coker turnarounds in 2004 as well as more reliable operations in the first half of the year compared to 2003. These increases were somewhat offset by operational issues encountered with the LC-Finer in the latter half of the year. Syncrude experienced an extended turnaround of its LC-Finer unit in the fall and then had to shut down that same unit in December as a result of a power outage related to a Syncrude electricity transformer. In 2003, Syncrude underwent two coker turnarounds, one of which was extended and the other unplanned, and also incurred unscheduled and extended scheduled maintenance, which impacted production more than the operational issues experienced in 2004.

The following table breaks down unit operating costs into its major components and shows bitumen costs on both a per barrel of bitumen and per barrel of SSB produced. This allows investors to better compare Syncrude's unit costs to other oil sands producers. As there are no definitions of what constitutes operating costs, different cost accounting and capitalization treatments are used among producers.

PURCHASED ENERGY COSTS

Stable operations and no coker turnaround in 2004 lowered per barrel energy costs from 2003. The per GJ cost of natural gas was unchanged.



	2004		2003	
	$/bbl Bitumen	$/bbl SSB	$/bbl Bitumen	$/bbl SSB
Bitumen Costs [1]				
Overburden removal	**1.78**		2.33	
Bitumen production	**6.12**		6.17	
Purchased energy [3]	**1.89**		1.67	
	9.79	**11.58**	10.17	12.13
Upgrading Costs [2]				
Bitumen processing and upgrading		**3.27**		3.82
Turnarounds and catalysts		**0.71**		1.86
Purchased energy [3]		**2.00**		2.45
		5.98		8.13
Other and research		**1.05**		0.81
Change in treated and untreated inventory		**0.05**		(0.05)
Syncrude reported operating costs		**18.66**		21.02
Natural gas hedging gains		**–**		(0.23)
Canadian Oil Sands adjustments [4]		**0.74**		0.33
Total operating costs		**19.40**		21.12
Syncrude production volumes (thousands of barrels per day)	**282**	**238**	252	212

1 Bitumen costs relate to the removal of overburden, oil sands mining, bitumen extraction and tailings dyke construction and disposal costs. The costs are expressed on a per barrel of bitumen production basis and converted to a per barrel of SSB based on the yield of SSB from the processing and upgrading of bitumen.

2 Upgrading costs include the production and ongoing maintenance costs associated with processing and upgrading of bitumen to SSB. It also includes the costs of major refining equipment turnarounds and catalyst replacement.

3 Natural gas prices averaged $6.28/GJ in each of 2004 and 2003.

4 Canadian Oil Sands' adjustments primarily relate to pension costs, site restoration costs, as well as the inventory impact of moving from production to sales as Syncrude reports per barrel costs based on production volumes and we report based on sales volumes.

From the operating cost table, which reflects costs on both a per barrel of bitumen and SSB basis, the most significant change was the decrease in per barrel upgrading costs. The decrease reflected the lower turnaround and maintenance costs associated with the LC-Finer issues in 2004 compared to the significant costs and production impact of the two coker turnarounds in 2003. Total bitumen costs decreased in 2004 from the prior year, both on a per barrel of bitumen and SSB basis, mainly as a result of lower overburden removal costs due to overall higher bitumen production and more production from the Aurora mine, which has a better strip ratio and is more efficient compared to the other two mines. The improvement in overburden removal costs was offset slightly by higher energy costs as a result of more purchased energy at the Aurora mine. The Base and North mines benefit from the close proximity of the Mildred Lake plant, where most of the excess energy produced at the plant is used to reduce the purchased energy requirements of those mines, compared to the Aurora mine which receives only a portion of that excess energy.

We had originally budgeted Syncrude production to reach 86 million barrels in 2004 assuming no coker turnarounds and only normal maintenance and tie-ins for the Stage 3 expansion. We revised our forecast to 87.3 million barrels during the year to reflect the strong performance in the first half of 2004. Syncrude surpassed our original budget volumes as a result of its strong operational performance in the first half of the year, and was only slightly below our revised forecast as a result of the LC-Finer complications in the fourth quarter.

Our original operating cost budget for 2004 was $18 per barrel, based on a natural gas cost of $5.60/GJ. We revised our operating costs outlook to $19 per barrel based on the extended LC-Finer turnaround in the fall as well as to increase natural gas costs to $6.72/GJ. Actual costs of $19.40 per barrel were higher primarily as a result of the costs associated with the LC-Finer maintenance.

Non-Production Costs

Non-production costs increased in 2004 from 2003 due to more research and development costs at Syncrude, higher levels of development activity associated primarily with Stage 3's upgrader expansion ("UE-1"), and our larger Syncrude working interest. Non-production costs consist primarily of development expenditures relating to capital programs, which are expensed, such as pre-feasibility engineering, technical and support services, research and development, and regulatory and stakeholder consultation expenditures.

Crown Royalties Expense

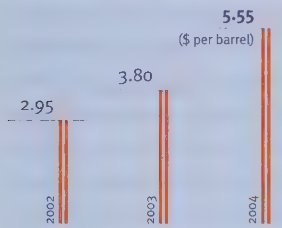
Crown royalties were higher in 2004 than 2003 mostly as a result of the increase in gross revenues. Crown royalties expense continued to reflect the one per cent of gross revenue royalty rate in each of 2004 and 2003. In addition, there was almost $2 million paid in 2004 for a settlement with the Crown in respect of the interpretation of certain calculations of the Royalties pertaining to prior years. In 2003 a similar amount was paid which related to an adjustment of the calculation of the Crown royalties for 2000. As Syncrude is currently undertaking a significant capital program, we expect to pay only the minimum one per cent royalty on our gross revenues in 2005, based on our current forecast. However, the continuation of strong crude oil prices likely will result in Crown royalties moving to 25 per cent of revenue, less applicable transportation, operating, non-production and capital costs, in 2006 or 2007. A description of the Crown royalties can be found in Note 18 of the audited consolidated financial statements for the year ended December 31, 2004.

Insurance Expense

The largest component of our insurance expense relates to premiums paid for business interruption ("BI") insurance, which is designed to protect the Trust's cash flow from the potential of a severe property loss at Syncrude. When we acquired the additional 13.75 per cent working interest in Syncrude in 2003, we increased our property and BI coverage. Insurance expense in 2003 reflected this increase in coverage subsequent to the acquisitions, and reflected the full coverage for twelve months of 2004, thereby increasing insurance expense slightly in 2004. Insurance is an important risk management component of our Stage 3 financing plan as it helps to protect our cash flow

DEPRECIATION, DEPLETION AND ACCRETION EXPENSE

The increase in DD&A expense in 2004 reflects the full inclusion of our share of Stage 3 costs, offset somewhat by an increase in the depletable reserve base.



from which our share of the capital expenditure commitments are largely funded. Once Stage 3 is complete and our debt levels have been reduced, we will re-evaluate our business interruption insurance program. Insurance is discussed more fully in the Risk Management section of this MD&A.

Interest Expense, Net

($ millions)	2004	2003	$ Change	% Change
Interest expense	**98.9**	72.0	26.9	37
Interest income and other	**(3.6)**	(4.2)	0.6	(14)
Interest expense, net	**95.3**	67.8	27.5	41

The increase in interest expense primarily reflects the additional debt levels outstanding during 2004 compared to 2003 as a result of debt issued in January, June and August of 2004 and during 2003, in addition to the utilization of our credit facilities. The new debt was issued to fund our share of Syncrude's Stage 3 capital program and to fund a portion of the acquisitions of the 10 and 3.75 per cent working interests acquired in February and July of 2003, respectively. Our financings are more fully discussed in the Liquidity and Capital Resources section of this MD&A.

Depreciation, Depletion and Accretion Expense

($ millions)	2004	2003	$ Change	% Change
Depreciation and depletion	**170.3**	91.7	78.6	86
Accretion expense	**1.6**	0.8	0.8	100
	171.9	92.5	79.4	86

Excluding accretion expense, depreciation and depletion ("D&D") expense in 2004 increased as a result of a significantly higher D&D rate, increased Syncrude production volumes, and a larger Syncrude working interest compared to 2003. The effective D&D rate in 2004 was $5.50 per barrel compared to $3.69 per barrel in 2003. The increase in the D&D rate in 2004 relative to 2003 reflects the full inclusion of our share of current estimated total Stage 3 costs of approximately $2.8 billion, partially offset by an increase to the depletable reserve base.

We depreciate and deplete our production assets and future development costs on a unit-of-production basis, based on proved plus probable reserves since National Instrument 51-101 provides that the total of proved plus probable reserves is the most likely estimate of an entity's reserve base. In prior years, we depreciated and depleted our assets based on proved reserves. These revisions to our D&D rate calculation have been accounted for as a change in estimate on a prospective basis.

Subsequent to year-end 2004, Canadian Oil Sands' 2004 reserve report was completed by independent reserve evaluators. The reserve report resulted in no significant revisions in our reserve base with proved plus probable reserves totalling 1.8 billion barrels. We estimate the 2005 D&D rate will be $6.10 per barrel, or approximately $180 million in D&D expense, based on our 2005 production budget of approximately 30 million barrels net to the Trust.

Also included in depreciation, depletion and accretion expense are amounts related to our asset retirement obligation. Effective January 1, 2004 we retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") new accounting standard for asset retirement obligations ("ARO") as explained in Note 3(a) of the annual consolidated financial statements. In prior years, a future site reclamation provision was calculated on a unit-of-production basis using total estimated future reclamation expenditures and proved reserves. The provision was recorded in net income and accumulated on the Consolidated Balance Sheet as a future site reclamation liability. Under the new accounting standard, the discounted estimated fair value of the future reclamation liability is now recorded on our Consolidated Balance Sheet as an increase to capital assets and as an asset retirement obligation. The depreciation expense on the asset and the accretion expense on the obligation are recorded in depreciation, depletion and accretion expense. Prior year's financial statements have been restated for the change in accounting policy. For 2003, the depreciation and accretion expense recorded under the new ARO accounting standard compared to the reclamation provision booked under the former accounting policy decreased by approximately $2.2 million. At December 31, 2004 the asset retirement obligation recorded on the Consolidated Balance Sheet was $44 million.

Canadian Oil Sands deposits $0.1322 per barrel of production into mining reclamation trust accounts for its 35.49 per cent Syncrude working interests. Including interest earned on the trust accounts, the reclamation fund accounts totalled $21 million at December 31, 2004 as shown on the Consolidated Balance Sheet under the heading "Reclamation trust".

Foreign Exchange Gains

Foreign exchange gains of $80 million and $135 million were recorded for 2004 and 2003, respectively. As required by GAAP, Canadian Oil Sands' U.S. denominated monetary balances are revalued at the foreign exchange rate at each period end, and the translation gains or losses are recorded in the current period net income. Our most significant U.S. denominated monetary balances that give rise to most of the foreign exchange impacts are our U.S. Senior Notes.

At December 31, 2004 and December 31, 2003 we had US$944 million and US$694 million in U.S. denominated Senior Notes, respectively. The stronger Canadian dollar at December 31, 2004 compared with December 31, 2003 created non-cash foreign exchange gains on the U.S. denominated Senior Notes of $89 million in 2004. At December 31, 2003 the stronger Canadian dollar compared with December 31, 2002 created non-cash foreign exchange gains on the U.S. Senior Notes of $147 million for 2003. We also have U.S. denominated cash, accounts receivable, and interest payable accounts that are revalued at the end of each period. The transactions on these accounts give rise to realized foreign exchange gains and losses which comprise the remaining balance of the foreign exchange gains and losses on the income statement.

Income and Large Corporations Tax

Large Corporations Tax ("LCT") expense in 2004 reflects the estimated LCT payable by COSL. As a result of the 13.75 per cent Syncrude working interest acquisitions in 2003 and Stage 3 capital expenditures, COSL's taxable capital base in 2004 is significantly higher than in 2003. However,

during 2004 the federal government enacted a reduction to the LCT rate to 0.2 per cent from 0.225 per cent, and the taxable capital threshold was increased from $10 million to $50 million for the 2004 taxation year. These favourable tax changes lessened the increase in LCT expense that would have otherwise occurred as a result of the increase in COSL's capital base in 2004 compared to 2003. For 2004, we expect that there will be no cash income taxes payable, other than LCT, by the Trust or any of its subsidiaries. Included in the federal government's 2004 tax changes is the elimination of LCT by the end of 2007, which we expect will increase the Trust's cash flow correspondingly.

Income and Large Corporations tax expense included a $9 million recovery in 2004. The recovery pertained to a reimbursement by the Trust's former tax service provider for a tax liability the Trust incurred in 2003 as a result of an error the service provider had made in filing the Trust's 2001 tax return. The tax payment was recorded as a $9 million tax expense in 2003 and the issue was disclosed as a contingent gain in the notes to the Trust's 2003 consolidated financial statements. The full amount of the settlement in 2004 was approximately $10 million, which included $1 million related to the reimbursement of the interest and penalties the Trust originally paid on the tax liability. The $1 million balance has been recorded as a reduction to interest expense and is reflected in "Interest, net" on the Consolidated Statement of Income and Unitholders' Equity. Also included as a one-time adjustment and reduction to LCT and other expense is an unrelated tax refund of approximately $2 million associated with prior years.

At the Unitholder level, distributions made from the Trust are either taxable to Unitholders or tax-deferred. Tax-deferred treatment reduces the Unitholders' tax-cost base. For the distributions related to 2004, 83 per cent of distributions were taxable, and 17 per cent were tax-deferred, unchanged from the prior year.

The taxable portion of distributions is dependent upon income and tax deductions available to shelter this income at both the Trust and the corporate level. Income, and therefore, taxable distributions to Unitholders, is highly sensitive to changes in revenues and costs since the annual tax deductions available are subject to maximum amounts. The tax balances available are disclosed in Note 12 to the consolidated financial statements. It is anticipated that the majority of future distributions will be taxable to Unitholders.

Future Income Tax

The difference between the accounting basis and tax basis for assets and liabilities is referred to as a temporary difference for purposes of calculating future income taxes. The future income tax liability of Canadian Oil Sands primarily represents the temporary difference between the book value of capital assets and tax pools of the Trust's subsidiaries at the substantively enacted tax rates as at December 31, 2004. The future income tax liability recorded on the Trust's Consolidated Balance Sheet is a requirement under GAAP, but is not expected to result in higher cash taxes being paid by Canadian Oil Sands in the future.

In 2004, Canadian Oil Sands recorded a non-cash future income tax recovery of $27 million, of which approximately $10 million pertains to the decrease in the statutory tax rates during the year. Effective April 1, 2004, changes to the Alberta corporate tax rate were substantively enacted, which reduced the income tax rate to 11.5 per cent, from 12.5 per cent previously. The remaining $16 million future income tax recovery is primarily a result of the decrease in temporary differences in the year.

In 2003, Canadian Oil Sands recorded a non-cash future income tax recovery of $2 million. Included in the $2 million recovery is a future income tax expense of approximately $13 million, which reflects the increase in COSL's future income tax liability as a result of the federal government substantively enacting the phasing out of resource allowance, partially offset by the reduction of corporate tax rates, over the next five years. Offsetting this expense was a future income tax recovery of approximately $15 million, which relates primarily to the decrease in the temporary differences in the year.

CRITICAL ACCOUNTING ESTIMATES

A critical accounting estimate is considered to be one that requires us to make assumptions about matters that are highly uncertain at the time the accounting estimate is made, and if different estimates were used, would have a material impact on our financial results. Canadian Oil Sands makes numerous estimates in its financial results in order to provide timely information to users. However, the following estimates are considered critical:

a) Canadian Oil Sands must estimate the reserves it expects to recover in the future. Our reserves are evaluated and reported on by independent petroleum reserve evaluators who evaluate the reserves using various factors and assumptions, such as forecasts of mining and extraction recovery and upgrading yield based on geological and engineering data, projected future rates of production, projected operating costs and oil price differentials, and timing and amounts of future development costs, all of which are subjective. Although reserves and forecasts of future net revenues are estimates, we believe that the factors and assumptions used in the estimates are reasonable based on the information available at the time that the estimates are prepared. The reserves data is reviewed by management, our own engineer, our Audit Committee, which acts as our reserves committee, and our Board of Directors.

As circumstances change and new information becomes available, the reserves data could change. After having independent reserve reports completed for years 2000, 2003 and 2004, our proved reserves overall have not changed significantly in the last four years, with the exception of adding a pro rata increase to our reserve base related to the additional 13.75 per cent working interest acquisition in 2003. However, future actual results could vary greatly from our estimates, which could cause material changes in our unit-of-production D&D rates and asset impairment tests, all of which use the reserves and/or future net cash flows in the respective calculations. If proved plus probable reserves were 10 per cent lower, D&D expense would have been approximately $19 million higher in 2004. Our impairment test is based on proved reserves, and had such reserves been 10 per cent lower, there still would not have been any impairment as of December 31, 2004.

b) Canadian Oil Sands records its asset retirement obligation and corresponding asset based on the estimated discounted fair value of its 35.49 per cent share of Syncrude's future cash flows that will be required for reclamation of each of Syncrude's mine sites. In determining the fair value, Canadian Oil Sands must estimate the amount of the future cash payments, the timing of when those payments will be required, and then apply an appropriate credit-adjusted risk free rate. Given the long reserve life of Syncrude's leases, we have estimated that the reclamation expenditures will be made over the next 45 years, with the majority of the payments not being incurred for another 30 years at which time the Aurora Mine is expected to be reclaimed. Therefore, it is difficult to estimate the timing and amount of the reclamation payments that will be required as they will occur a long time after the date the estimate was originally made.

Any changes in the anticipated timing or the amount of the payments subsequent to the initial obligation being recorded results in a change to our asset retirement obligation and corresponding asset. Such changes will impact the accretion of the obligation and the depreciation of the asset and will correspondingly impact net income. However, as the payments extend so far into the future, the changes to the cash flow estimates would have to be significant to make even a $1 million impact on the Trust's net income in any particular year. To illustrate, in order to impact the accretion expense by more than $1 million in 2004, the undiscounted cash flow estimate would have to have been approximately $180 million higher than our current estimate of approximately $275 million.

c) Canadian Oil Sands accrues its obligations for Syncrude Canada's employee post retirement benefits utilizing actuarial and other assumptions to estimate the projected benefit obligation, the return on plan assets, and the expense accrual related to the current period. The basic assumptions utilized are outlined in Note 7(a) to the consolidated financial statements. In addition, actuarial gains and losses are deferred and amortized into income over the expected average remaining service lives of employees which is estimated to be 13 years. Actual costs related to Syncrude Canada's employee benefit plans could vary greatly from the amounts accrued for the pension obligation and the plan assets. If Canadian Oil Sands had recognized the actuarial losses immediately into income, pension and other post retirement expense would have increased from $26 million to approximately $55 million in 2004. In addition, the accrued benefit liability on the Consolidated Balance Sheet would have increased from $93 million to $201 million. Canadian Oil Sands does not have a pension plan for its own employees. Therefore, all of its employee future benefit liabilities and expenditures relate to its working interest share of Syncrude Canada's pension plan and post-retirement plan obligations.

d) Canadian Oil Sands must estimate its future tax liability at the end of each reporting period based on estimates of temporary differences, when those temporary differences are expected to reverse, and the tax rates at which they will reverse. However, actual tax rates at which the temporary differences will reverse and the amount of the temporary differences may differ from our estimates, which may result in material changes in our future income tax liability and future income tax expense or recovery. While these changes may impact net income, we do not believe there will be any impact on the future cash taxes Canadian Oil Sands will pay.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2004 we retroactively adopted the CICA's accounting standard "Asset Retirement Obligations". The impact of the change in this accounting policy is described in Note 3(a) of the consolidated financial statements.

Also effective January 1, 2004 was the CICA's Accounting Guideline 13, "Hedging Relationships" ("AcG-13"), which establishes certain conditions as to when hedge accounting may be applied. Canadian Oil Sands is applying AcG-13 to its financial derivatives, the impacts of which are described in the Risk Management section of this MD&A and in Note 3(b) of the consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

We do not anticipate any significant changes to our accounting policies in 2005 as a result of new accounting pronouncements which have been issued. While there have been changes proposed by the Accounting Standards Board to the calculations of diluted net income per Unit for the 2005 year, as at February 21, 2005, the amendments have not been finalized. We do not expect there to be any impact on our diluted net income per Unit results if the changes do come into effect as the Trust has few options outstanding relative to its total Units.

Effective January 1, 2005 Accounting Guideline 15 ("AcG-15") "Consolidation of Variable Interest Entities" is applicable, which requires the Trust to consolidate any entities that it controls on a basis other than the ownership of voting interests. Such control would exist if the Trust's variable interest in another entity were to absorb a majority of that variable interest entity's ("VIE") expected losses, receive a majority of its returns, or both. At February 21, 2005 the Trust does not have any VIEs, and therefore, we do not anticipate any impact on Canadian Oil Sands' results as a consequence of AcG-15.

On December 9, 2004 the CICA issued EIC-150 "Determining Whether an Arrangement Contains a Lease", which will be effective for the Trust as of January 1, 2005 for new contracts, arrangements or amendments to existing contracts entered into after that date. The potential impact on Canadian Oil Sands is currently being evaluated.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	**2004**	2003
Long-term debt	**1,699.8**	1,437.4
Less: Cash and short-term investments	**17.8**	16.7
Net debt	**1,682.0**	1,420.7
Unitholders' equity	**2,635.9**	2,102.9
Total capitalization [1]	**4,317.9**	3,523.6

[1] Net debt plus Unitholders' equity

A main objective for the Trust in 2004 was prudent financing of our share of Syncrude's capital program by maintaining a strong capital structure. At December 31, 2004 the Trust's capitalization had increased from the prior year as a result of robust crude oil prices, strong Syncrude operations, coupled with new equity and additional borrowings used to finance our share of Syncrude's capital expenditure program. As part of our ongoing compliance under our debt and credit facilities, we monitor the following financial leverage ratios:

FINANCIAL LEVERAGE RATIOS

	2004	2003
Net debt to cash flow (times)	**2.9**	5.2
Net debt to total capitalization (%)	**39**	40

A key benchmark used to evaluate the Trust's performance is return on average productive capital ("ROCE"), which is a measure of the returns the Trust realizes on its assets that are in productive use. In calculating ROCE, we exclude major projects that are not yet used in production, such as the UE-1 component of the Stage 3 expansion. The Trust's ROCE, and also its return on average Unitholders' equity, improved in 2004 over 2003 primarily as a result of higher realized prices and stronger operating results at Syncrude in the first half of 2004 and no coker turnarounds in the year, compared with 2003 which experienced two coker turnarounds.

PERFORMANCE MANAGEMENT RATIOS

	2004	2003
Return on average Unitholders' equity (%)	**21**	20
Return on average productive capital employed (%) [1]	**21**	14

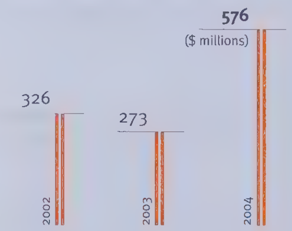
[1] Calculated as net income before net interest expense, future income tax recoveries and foreign exchange gains, divided by average productive capital employed, which excludes major projects not yet in use.

On July 30, 2004 we closed a private placement equity issue of three million Units with a large Canadian investor at a subscription price of $48.00 per Unit for total proceeds of $144 million. The equity issue contributed to a stronger balance sheet and reduced the need for further hedging activity. Under the current conditions, we do not anticipate any further equity issues will be required to assist in financing the remaining Stage 3 expansion costs, outside of Canadian Oil Sands' Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP").

In 2004, COSL completed various debt financings. On January 15, 2004 COSL issued $20 million of floating rate and $175 million of 3.95% medium term notes. Both issues were for three-year terms. Interest rate swap transactions were undertaken to effectively convert the fixed interest rate on the $175 million notes to a floating rate based on three-month bankers' acceptance rates plus a credit spread. On June 29, 2004 COSL issued another $200 million of medium term notes bearing interest at 5.55% and with a five-year term. On August 9, 2004 COSL issued US$250 million

FUNDS FROM OPERATIONS

A larger Syncrude working interest, increased Syncrude production and a higher realized selling price resulted in record funds from operations in 2004.



of 4.8% Senior Notes in the United States, which mature on August 10, 2009. The proceeds from the equity and debt financings were used to fund our share of Syncrude's capital program and to repay borrowings under our bank credit facilities. All of these issues were unsecured and rated at BBB+ with a negative outlook from Standard & Poor's and Baa2 with a negative outlook from Moody's Investor Service.

We have $685 million of available bank facilities and lines of credit. At December 31, 2004 including lines of credit drawn, approximately $57 million was utilized, leaving approximately $628 million of these $685 million credit facilities available. In addition, we had approximately $18 million of cash and short-term investments at December 31, 2004.

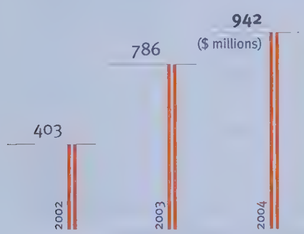
Funds generated from operations continued to be an important source of funding. In 2004, funds from operations totalled a record $576 million, or $6.47 per Unit. These results are significantly higher than in 2003, which generated $273 million, or $3.43 per Unit. The increase is primarily as a result of a larger Syncrude working interest, increased production as there were no coker turnarounds in 2004, and a higher realized selling price in 2004 offset somewhat by higher operating and financing costs. In 2004, $547 million of the total $942 million spent on capital expenditures was funded through new debt and equity issuances. The remaining $395 million of capital expenditures was financed with the funds generated from our operations after deducting Unitholder distributions. At the end of 2004, we had a working capital deficiency of $103 million, comparable to the deficiency at December 31, 2003. The deficiency continues to reflect significant accounts payable balances largely relating to our share of Syncrude's capital expenditures.

A significant component of our financing plan for the Stage 3 Syncrude expansion is the DRIP as it enables the Trust to raise new equity at a relatively low cost with no dilution to participating Unitholders, and it supports the Trust's ability to maintain distribution levels during the expansion period. DRIP participation increased to 33 per cent in 2004 from approximately 30 per cent in the prior year, and generated almost $60 million in new equity through the issuance of 1.3 million Units, compared with approximately $48 million and the same number of Units in 2003. Since inception of the DRIP in 2002, the issuance of 3.5 million Units has generated $140 million.

Overall, our financing requirements primarily depend on the funds we generate from operations and the DRIP, our share of Syncrude's capital expenditures, and the distributions we make to the Trust's Unitholders. In 2005, we estimate the Trust's funds from operations will total $580 million, or $6.29 per Unit, which will be used to fund a portion of the $691 million of capital expenditures we are estimating for the year. Our available credit facilities and DRIP proceeds anticipated for 2005 are expected to be adequate sources of financing to fund the remaining capital expenditures.

CAPITAL EXPENDITURES

The increase in capital expenditures reflects our larger Syncrude working interest and higher capital spending by Syncrude in 2004.



Capital Expenditures

In 2004, we incurred capital expenditures of $942 million, an increase of approximately $157 million from the prior year. The increase is primarily due to the Trust's higher working interest ownership in Syncrude and higher capital spending by Syncrude on an annual basis. Syncrude's capital expenditures relate largely to the Stage 3 expansion and the installation of a third mining system at the Aurora North mine and an auxiliary production system at the North Mine. The additional mining systems are required to replace bitumen production from the southwest quadrant of the Base Mine, which we anticipate will be depleted by the fall of 2006. In 2004, Syncrude expended approximately $2.0 billion, or $0.7 billion net to the Trust, on the expansion, and $0.4 billion, or $0.1 billion net to the Trust, on the Base Mine replacement. Stage 3 capital and Base Mine replacement costs accounted for approximately 88 per cent of our total capital expenditures in 2004. The remaining capital expenditures relate primarily to our share of Syncrude's sustaining capital. After revisions were made to the total Stage 3 project cost in March 2004, actual capital expenditures in 2004 were in line with our anticipated expenditures for the year of $1 billion.

In 2003, approximately 88 per cent of the total $786 million recorded as capital expenditures related to our share of Syncrude's Stage 3 capital costs. The additional 13.75 per cent working interest acquired in 2003 accounted for $256 million of the year's total capital expenditures.

As of December 31, 2004 construction of the UE-1 component of Stage 3 was approximately 75 per cent complete, surpassing the 70 per cent completion goal for the end of 2004. Our estimated share of Syncrude's total Stage 3 costs projection, which includes both capital and costs that will be expensed as non-production costs, remains unchanged at $2.8 billion, of which the remaining $0.5 billion will be spent over the next two years, the majority of which will be incurred in 2005.

The Outlook section of this MD&A discusses future commitments related to Stage 3 and the Trust's anticipated total capital expenditures in 2005. In addition to our other contractual obligations, the table on page 34 outlines the purchase commitments we have in place related to Stage 3 and Base Mine replacement projects.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have assumed various contractual obligations and commitments in the normal course of our operations. In the following table are significant financial obligations that are known as of February 21, 2005, which represent future cash payments that we are required to make under existing contractual agreements that we have entered into either directly, or as an owner in the Syncrude Joint Venture.

CONTRACTUAL OBLIGATIONS

($ millions)	Total	Payments due by period < 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt [1]	1,699.8	–	297.9	650.9	751.0
Stage 3 expenditure obligations [2]	519.0	499.0	20.0	–	–
Capital expenditure commitments [3]	269.7	130.6	139.1	–	–
Pension plan solvency deficiency payments [4]	33.1	8.3	24.8	–	–
Other obligations [5]	170.6	115.5	14.3	7.3	33.5
	2,692.2	753.4	496.1	658.2	784.5

[1] The long-term debt repayment schedule is outlined in Note 9(i) to the consolidated financial statements.

[2] The total estimated cost of the Stage 3 expansion is approximately $2.8 billion, net to the Trust, of which we have spent approximately $2.3 billion as of December 31, 2004.

[3] Capital expenditures commitments is comprised of $0.2 billion related to our 35.49 per cent share of Syncrude's emissions reduction program, and $0.1 billion related to our share of remaining capital costs for additional mining systems at the Aurora North and North mines to replace production from a portion of the Base Mine that will be depleted by 2006.

[4] We are responsible for funding our 35.49 per cent share of Syncrude Canada's registered pension plan solvency deficiency, which was confirmed in the December 31, 2003 actuarial valuation that was completed in 2004.

[5] These obligations primarily include our 35.49 per cent share of the minimum payments required under Syncrude's commitments for natural gas purchases, annual disposal fees for the flue gas desulphurization unit, pipeline cost of service fees as described in Note 19 to the consolidated financial statements, and capital and operating lease obligations.

UNITHOLDERS' CAPITAL

Canadian Oil Sands Trust's Units trade on the Toronto Stock Exchange under the symbol COS.UN. As of February 21, 2005 the Trust had 91.4 million Units outstanding. Canadian Oil Sands' Unit price closed at $79.25 on February 21, 2005, resulting in market capitalization of the Trust being approximately $7 billion.

Unitholder distributions related to 2004 were $180 million, or $2 per Unit, compared with $170 million, or $2 per Unit in 2003. A Unitholder distributions schedule is included in Note 16 to the consolidated financial statements. During the Stage 3 expansion at Syncrude, we have utilized debt and equity to finance capital expenditures to the extent funds from operations have not been sufficient to fund the Trust's distributions and capital expenditures. Such financings are disclosed as "non-acquisition financing, net" on the Unitholder distributions schedule.

Canadian Oil Sands issues Unit options ("options") as part of its long-term incentive plan for employees. There were 102,500 options granted in 2004, and another 96,000 granted on January 28, 2005. As of February 21, 2005 there were 522,400 options outstanding, representing less than 1 per cent of Units outstanding, with a weighted average exercise price of $46.73 per option, of which 207,625 were exercisable at a weighted average price of $40.03 per option. Each option represents the right of the option holder to purchase a Unit at the exercise price determined at the date of grant. The options vest by one-third following the date of grant for the first three years and expire seven years from the date of grant.

RISK MANAGEMENT

There are many financial and operational risks inherent in the oil sands business, which include, but are not limited to: commodity price, currency exchange, interest rate, capital, credit, regulatory, operational and environmental risks. We take specific measures to manage these risks, particularly those that affect funds from operations and capital expenditures, as these have a direct impact on the Trust's distributable income available to Unitholders.

Commodity Price Risk

Crude Oil Price Risk We employed crude oil hedging as a risk mitigation strategy for our Stage 3 financing plan in 2004 and prior years. Our cash flows are impacted by changes in both the U.S. dollar denominated crude oil prices and U.S./Canadian foreign exchange rates. As a result, from time to time management has hedged both elements to reduce revenue and cash flow volatility to the Trust. These elements can be hedged separately with U.S. dollar WTI crude oil hedges and foreign currency hedges, which are outlined in the Foreign Currency Risk section of the Risk Management discussions in this MD&A, or by combining both elements with Canadian dollar oil price hedging transactions. We have used both strategies. With just over one year remaining in the Stage 3 expansion, the strong balance sheet of the Trust, and robust energy prices anticipated for the year, the Trust's financing risk for the expansion has been reduced significantly. Therefore, at February 21, 2005 based on current expectations, we do not have any crude oil hedges in place.

Crude oil hedging losses in 2004 were $274 million, or $8.86 per barrel, compared to $100 million, or $4.10 per barrel in 2003. In 2004, WTI prices averaged US$41.47 per barrel, and Canadian dollar WTI prices averaged $53.58 per barrel, compared to 2003 when WTI prices averaged US$30.99 per barrel. There were no Canadian dollar WTI hedges in place in 2003.

Effective January 1, 2004 Canadian Oil Sands adopted AcG-13 related to hedging relationships. Under the new guideline, our crude oil hedge positions qualify for hedge accounting and therefore there was no impact on our financial results for these positions as a result of the new guideline.

In the past 18 months, there have been significant increases to the supply of synthetic crude oil from various other oil sands projects, with several additional projects being contemplated. If and when these other projects are completed, there will be a significant increase to the supply of synthetic crude oil in the market. There is no guarantee there will be sufficient demand to absorb the increased supply without eroding the selling price, which could result in a widening in the price differential that Canadian Oil Sands may realize as compared to benchmark prices such as WTI. Also, prices may decline to such an extent that our share of Syncrude's production is no longer economically viable. In response to growing volumes of synthetic crude oil and Syncrude's own expanding volumes following the Stage 3 completion, we will likely have to expand our markets to achieve the premium price we expect for our quality product. When UE-1 is complete, a new aromatic saturation unit will be used to further upgrade our entire production into SSP. We expect this higher quality blend to be more attractive to refineries, which should enhance our price per barrel.

Also, the use of light sweet synthetics as a blend stock for bitumen to produce "synbit" is seen as a growing new market for SSB. Currently, heavy crude oil producers are shipping bitumen to U.S. refineries by adding condensate, which is expensive and in short supply. Synbit, which is similar to medium sour crude, has developed as an alternative.

Natural Gas Price Risk For the period April 2002 to March 2003, we held a forward purchase contract for 20,000 GJ per day of natural gas at an average AECO price of $3.44 per GJ, representing approximately 60 per cent of our share of forecast Syncrude consumption during that time period. The Trust had entered into the hedge to reduce the volatility of purchased energy costs which are a significant component of our operating costs. The resulting hedging gains reduced 2003 operating costs by $6 million. No natural gas hedges were utilized in 2004 and as at February 21, 2005 we have no natural gas hedges in place. Natural gas hedges will continue to be assessed as a strategy to manage operating costs, primarily during the winter season.

Foreign Currency Risk Our results are affected by fluctuations in the U.S./Canadian currency exchange rates as we generate revenue from oil sales based on a U.S. dollar benchmarked price. This revenue exposure is partially offset by interest in U.S. dollars on our U.S.-denominated debt, and our share of Syncrude's U.S. dollar vendor payments. When our U.S. Senior Notes mature, we will have exposure to U.S. exchange rates on the repayment of the notes. We have reduced our currency exchange risk by entering into contracts that fix our exchange rate in future years. At the present time we do not intend to increase our currency hedge positions. The details of our foreign currency contracts are more fully described in Note 17(a) of the consolidated financial statements. The existing positions are as follows:

	2005	2006	2007
U.S. dollars hedged ($ millions)	$ 100.0	$ 60.0	$ 20.0
Average U.S. dollar exchange rate	$ 0.664	$ 0.669	$ 0.692

In 2004, we recorded approximately $13 million, or $0.42 per barrel, of foreign currency hedging gains, which reflect an average Canadian dollar of $0.77 US/Cdn for the year. In 2003, a foreign exchange gain of $4 million, or $0.15 per barrel, was reported. There was no impact to our 2004 results due to adopting AcG-13 since our foreign currency hedges continue to qualify as hedges under the new guidelines.

In 1999, we exchanged gains on closing certain forward currency contracts for adjustments to the terms of other currency contracts. For accounting purposes, this position of realized gains is deferred and will be recognized as revenue over the period 2006 to 2016, which is when the original forward contracts would have expired. In 2004, gains of approximately $5.7 million have been deferred. Cumulatively, Canadian Oil Sands has deferred recognition of gains totalling $28 million to 2006 and beyond for net income purposes, but these amounts are included in our funds from operations. The deferred balance is reflected in the Consolidated Balance Sheet under "Deferred currency hedging gains".

Interest Rate Risk Interest rate changes impact our net income and cash flows based on the amount of floating rate debt outstanding. At December 31, 2004 we had approximately $19 million drawn on our credit facilities, $20 million of floating rate medium term notes outstanding and had swapped $175 million of fixed rate debt into floating rate debt. The swaps have been recorded as hedges on the consolidated financial statements in 2004, and any gains or losses related to the swaps will be recognized in the period the swaps are settled.

Pursuant to AcG-13, the interest rate swaps into which COSL entered in 1997 relating to its US$70 million 7.625% Senior Notes do not qualify as hedges under the new guidelines. As a result, a deferred asset and a corresponding deferred liability, each with a fair value of approximately $5 million, were recorded on January 1, 2004. The asset and liability are included on the Consolidated Balance Sheet under the headings "Deferred financing charges, net and other" and "Employee future benefits and other liabilities", respectively. At the end of each quarter, the fair value of the interest rate swap is calculated, with the change in value from the prior quarter end recorded as other income or expense and is included in "Interest, net" in the current quarter net income. The deferred liability is being amortized as the swap contracts settle, with the amortization included as a reduction to interest expense. The amounts related to the change in fair value and the amortization of the deferred liability are immaterial. These interest rate swaps expire on May 15, 2007.

Capital Risk Inherent in the mining of oil sands and production of synthetic crude oil is a need to make substantial capital expenditures, such as the Stage 3 expansion. In addition to the potential of the overall Syncrude cost estimate for Stage 3 increasing from the current projected amount of $7.8 billion, or $2.8 billion net to the Trust, we are exposed to financing risks associated with the funding requirements for our 35.49 per cent interest as Syncrude progresses with the expansion. We have historically minimized this risk by accessing diverse funding sources. Credit facilities, funds generated from operations, and proceeds from the DRIP are significant sources of funding available to us. In addition, the Trust has the ability to access public debt and equity markets and this ability should be enhanced as the Trust increases in market size.

Credit Risk Crude oil sales revenue credit risk is managed by limiting the exposure to customers based on assigned credit ratings as well as limiting the maximum exposure to any single customer. Risk is further mitigated as sales revenue receivables are due and settled in the month following the sale. We mitigate our exposure to credit risk under financial instruments, such as commodity derivatives and foreign exchange contracts, by selecting counterparties of high credit quality. We have never experienced a loss on uncollected receivables from any customers or counterparties.

Operational Risk Currently, our investment in Syncrude represents our only asset. Therefore, the results of the Trust depend exclusively on the operations of Syncrude. As a participant in Syncrude, we benefit from operational risk management programs implemented by the joint venture. From an operations perspective, sustained, safe and reliable operations are the key to achieving targets for production and operating costs. Extreme cold weather can affect both ongoing operations and capital projects, such as construction on the Stage 3 expansion, by reducing worker productivity and potentially increasing natural gas consumption. Major incidents or unscheduled maintenance outages curtail production and result in significant increases to per barrel operating costs, which was evident in 2003 with the extended scheduled and unscheduled turnarounds of the two cokers at Syncrude and in 2004 with the LC-Finer issues. Syncrude has a history of 26 years of continuous production, and has one of the best industrial safety records.

In addition, we are exposed to the risks associated with major construction projects, such as the Stage 3 expansion. Such risks include the chance of the project not being completed on time and/or not reaching design capacity. Also, complications could arise when new systems are integrated with existing systems and facilities. The risk of such complications is somewhat mitigated by Syncrude's procedures of performing a sequenced start up of new units.

We manage our exposure to these operational risks by maintaining appropriate levels of insurance, primarily BI and property insurance. We have purchased US$1.2 billion of BI and property insurance to protect up to 18 months of cash flow in case Syncrude experiences an event causing a loss or interruption of production, such as a fire or explosion at the operating facilities. The BI insurance is subject to a 60 day self-retention period after which time an insurance claim can be made. Course-of-construction and start-up delay insurance coverages of approximately $210 million and $160 million, respectively, have also been purchased as part of the Stage 3 expansion.

We also face risks associated with other oil sands producers such as competition for skilled labour, limited resources in the Fort McMurray area where Syncrude and the other producers operate, or higher costs for products and services to operate Syncrude's facilities as a result of increased demand. In addition to paying its employees and contract staff competitive industry compensation, Syncrude Canada has a reputation as an innovative and socially responsible company committed to the environment and dedicated to its employees and the Aboriginal people and communities of northern Alberta, qualities which we believe assist in retaining skilled labour. To deal with the increased demands on the infrastructure, such as housing, Syncrude cooperates with other industry participants to share resources where they are able to.

Syncrude Joint Venture Ownership The Syncrude Project is a joint venture that is currently owned by eight participants, two of whom are subsidiaries of Canadian Oil Sands. Each Syncrude participant's working interest is equal to its pro rata interest in the Syncrude Project. Major capital

decisions for new projects require unanimity of the owners, while other matters require only the approval of a majority and three owners. Historically, however, the Trust's subsidiaries and the other joint venture owners have sought consensus of all the owners on all matters.

Syncrude is also a single interrelated and interdependent facility. While the shutdown of one part of the facility could significantly impact the production of synthetic crude oil, the Stage 3 expansion and other capital projects are designed to provide more flexibility than historically existed in allowing continued operation of a greater portion of the facilities, thereby protecting a portion of our cash flow. All of our Syncrude production is transported to Edmonton, Alberta through the Athabasca Oil Sands Pipeline Limited ("AOSPL") system. Disruptions in service on this system could adversely affect our crude oil sales and cash flows.

Environmental Risk We are exposed to the risk of the impact of Syncrude's operations on the environment. Mitigating this risk, Syncrude remains committed to its objectives for operational, environmental and social excellence. When Stage 3 is completed it will incorporate technologies to reduce emissions, improve energy efficiency and upgrade the entire production stream to meet higher specifications for environmental and product quality. As a result, we anticipate downstream refineries, in producing products such as gasoline and diesel, will use significantly less energy than is required by lower grades of crude oil, while affording a higher value for the new SSP product.

The third fluid coker being constructed as part of Stage 3 includes a flue gas desulphurizer that will capture SO_2 for use in ammonium sulphate fertilizer production. As described in Note 19(d) to the consolidated financial statements, Syncrude has an agreement in place with a third party to provide the sulphur from the desulphurization unit for at least the next 15 years. Syncrude is also retrofitting sulphur reduction technology into the operation of its two existing cokers. These initiatives are anticipated to result in a 60 per cent reduction in SO_2 emissions from the currently approved Alberta Environment regulatory limits. While total CO_2 emissions will increase as production increases, Syncrude's investments in energy consumption and environmental mitigation are anticipated to reduce CO_2 emissions by about 25 per cent per barrel from 1990 to 2008.

Syncrude produces and stores significant amounts of sulphur in a block at its plant site as there is presently a limited market for the sulphur. There can be no assurance that future environmental regulations pertaining to the use, storage, handling and/or sale of sulphur will not adversely impact the unit costs of production of synthetic oil. Syncrude is exploring the ability to store sulphur blocks underground. Initial information indicates that this may be a viable and environmentally friendly solution for dealing with the excess sulphur. Syncrude continues to research alternatives for addressing this issue, which also affects other sulphur producers in the petroleum industry. Canadian Oil Sands is also exploring other opportunities to effectively utilize the sulphur.

Syncrude owners are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Project. Our share of Syncrude's ongoing environmental obligations has been and is expected to continue to be funded out of our funds from operations. In addition, the owners have each directly posted letters of credit with the Province of Alberta to secure the ultimate mining reclamation obligations of the owners. In addition to the letters of credit posted with the Alberta government, Canadian Oil Sands maintains trust funds for such reclamation liability.

In each of 2004 and 2003, we contributed approximately $4 million, including earned interest, to our reclamation trust accounts. We anticipate that the mining reclamation trust contributions we will continue to deposit, along with the accumulating interest, will be sufficient to pay our original 21.74 per cent share of the Syncrude Joint Venture's anticipated mining environmental and reclamation costs. The 13.75 per cent Syncrude interests we acquired in 2003 historically did not have a mining reclamation trust account. Since acquisition, we have deposited an amount related to current production into one of the existing reclamation trust accounts on a basis similar to that being deposited for the 21.74 per cent interest held previously. The funding requirements of the reclamation trusts are more fully described in Note 10 to the consolidated financial statements.

A number of environmental regulations focus on limiting the emissions of gases and other substances from the Syncrude operations. The Canadian federal government ratified the Kyoto Protocol in 2002 and has indicated that total annual emissions for greenhouse gases for large industrial emitters have been capped at 55 megatonnes, with emissions to be reduced by 15 per cent from current business as usual levels. The government has limited the cost of future carbon credit purchases to a maximum of $15 per tonne. Based on these parameters, we have estimated a direct cost impact of $0.22 to $0.30 per barrel from 2008 to 2012 on Syncrude's operating costs for implementing the Kyoto Protocol, without further emission improvements. While further announcements regarding the Protocol were made in the February 23, 2005 Canadian federal budget release, no additional guidance on the cost or implementation related to the Protocol was provided.

With Russia's adoption of the Kyoto Protocol in 2004, the Protocol came into effect in Canada on February 16, 2005. However, the federal government still has not published guidelines or further guidance on its application to industry. Accordingly, numerous uncertainties regarding details of the Protocol's implementation make it difficult to estimate the full potential cost impact, such as third party supply chain costs related to the Protocol. While we believe that our cost estimate is a reasonable one, we have no assurance that the actual impact might not be substantially different from the estimate. However, we believe that production will continue to be profitable under the current known factors. Operationally, Syncrude also has moved towards lowering its emissions

of SO_2 and CO_2. Over time, the amount of SO_2 and CO_2 has been decreased on a per barrel basis as Syncrude has adopted new technologies and refining methods, such as the SO_2 scrubbing system as part of the Stage 3 expansion. The costs of meeting these environmental thresholds, however, increases operating costs and/or capital costs, and as such, may impact the profitability of the operations.

Regulations The Syncrude Project's operations are subject to extensive Canadian federal, provincial and local laws and regulations governing exploration, development, transportation, production, exports, occupational health, protection and reclamation of the environment, safety and other matters. Currently, we believe that Syncrude is in substantial compliance with all applicable laws and regulations. During the Stage 3 construction, Syncrude has achieved very high safety ratings in both the construction and operational aspects at the plant. Additionally, Syncrude has historically obtained renewals of its licenses and permits. While there can be no assurance that government approvals required for certain licenses and permits will be provided, we do not believe that there are any significant issues pending with the governmental authorities which would cause Syncrude to lose its rights. In particular, the approval granted by the Alberta Energy and Utilities Board for the Syncrude Project facility does not expire until December 31, 2035 and may be further extended upon application to the relevant regulatory authorities at the time.

Foreign ownership In the third quarter of 2004, the federal government tabled draft legislation which restricted the level of foreign ownership of mutual fund trusts on a continuous monitoring basis to 50 per cent. We strongly opposed this legislation and viewed any restriction on accessing the larger international capital markets as harmful to the Canadian economy and unnecessary in light of the proposed implementation of a 15 per cent withholding tax on all distributions made to non-resident Canadian unitholders. Canadian Oil Sands is a member of The Canadian Association of Income Funds ("CAIF"). CAIF commissioned an independent study by HLB Decision Economics which has shown that, with the proposed 15 per cent withholding tax on distributions to non-residents, the revenue to the federal government is not decreased but in fact may be increased by having a higher level of foreign ownership in trusts. In turn, the resource industry has traditionally relied on foreign capital to complete the large capital programs necessary to harness the vast resources of our country. Following consultation between the federal government and industry, including discussions with representatives of Canadian Oil Sands and a number of other mutual fund trusts, investment bankers and members of the business community, the federal government implemented the 15 per cent withholding tax but left the current legislation regarding foreign ownership unchanged. In our view, the 15 per cent withholding tax on distributions made to non-residents places the federal government in a revenue neutral position. We plan to continue consultations with the federal government on our own and as part of industry groups such as CAIF with a view to having open access to global capital markets and thereby allowing higher levels of foreign ownership in trusts.

The Trust uses declarations from Unitholders and geographical searches to estimate the level of Canadian and non-Canadian resident Unitholders of the Trust at certain periods throughout the year. While the Trust believes that these results are reasonable estimations at the time that they are provided, the inability of all public issuers to obtain the residency information of its beneficial holders means that issuers are reliant upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations and the level of Canadian ownership may change at any time without notice.

Based on account data at February 22, 2005, Canadian Oil Sands estimates that approximately 44 per cent of our Units are held by non-Canadian residents with the remaining 56 per cent being held by Canadian residents. We will continue to monitor the non-resident ownership levels. If at any time the Trustee of the Trust becomes aware that the 49 per cent ownership limit is imminent, it may publish a notice and require completion of residency declarations before the Trustee will complete any transfer of units.

If, based on the declarations or on the geographical list, the level of Units held by non-Canadian residents is 46 per cent or more, then Canadian Oil Sands plans to issue a press release advising of the increased level and stating that it is anticipated that the Trust may reach 49 per cent or more non-Canadian resident Unitholders and that, in such case, each person purchasing the Units, whether through a broker or directly in registered form will need to complete a declaration.

If the level of non-Canadian resident ownership appears to be approximately 49 per cent or more of non-Canadian residents, Canadian Oil Sands will make a public announcement that no further sales to non-Canadian residents will be allowed. No transfers will be allowed without the completion of a declaration indicating their status as a Canadian or non-Canadian resident. As part of such announcement, the Trustee shall state that it shall not accept a subscription for Units from or issue or register a transfer of Units to a person unless the person provides a declaration that the person is not a non-Canadian resident. In addition, the Trustee will send a notice to non-resident holders of Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable requiring them to sell their Units or a specified portion thereof within the specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Units or provided the Trustee with satisfactory evidence that they are not non-Canadian residents within such period, the Trustee may, on behalf of such Unitholders sell such Units and, in the interim, shall suspend the voting and distribution rights attached to such Units. Any sale shall be made on the Toronto Stock Exchange and, upon such sale, the affected holders shall cease to be holders of Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing the Units.

Unlimited liability Legislation came into effect in Alberta on July 1, 2004 to provide limited liability for holders of trust units, similar to protection afforded to investors of corporations. The legislation covers events that occur on or after July 1, 2004 and extends to all Unitholders of Canadian Oil Sands Trust, including non-residents. Recently, similar legislation was passed in Ontario.

Prior to July 1, 2004 unlike corporate statutes, the legislation governing the creation of trusts did not contain explicit language which limited the liability of Unitholders of the Trust to their equity investment in the Trust. As a result, there was a possibility that Unitholders of the Trust may not be protected from liabilities of the Trust to the same extent as a shareholder of a publicly traded corporation and that potentially, Unitholders could be liable for tort claims such as environmental claims. While this is a possibility, we believe that it is very remote. The trust indenture itself provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs or for any act or omission of the Trustee, provided that in the event that a court determines that Unitholders are subject to such liabilities, the liabilities will be enforceable only against and will be satisfied out of the Trust's assets. The trust indenture also provides that contracts to which the Trust is a party should contain language restricting the liability of Unitholders. Recently, the Trust obtained a legal opinion from external counsel which confirmed that the risk to a Unitholder is similar to the risk of a shareholder of a corporation.

Sensitivities

The following table provides an estimate of the impact that the crude oil and natural gas price risks, foreign currency risk, and operational risks have on the Trust's funds from operations and net income for 2005, based on our forecast for 2005 as described in the Outlook section of this MD&A:

2005 SENSITIVITY ANALYSIS

		Funds from Operations Increase		Net Income Increase	
Variable [1]	Sensitivity	$ millions	$/Trust unit	$ millions	$/Trust unit
Syncrude operating costs decrease	C$1.00/bbl	30	0.33	30	0.33
Syncrude operating costs decrease	C$50 million	18	0.20	18	0.20
WTI crude oil price increase	US$1.00/bbl	37	0.41	37	0.41
Syncrude production increase	2 million bbls	32	0.35	28	0.31
Canadian dollar weakening	US$0.01/C$	16	0.18	1	0.02
AECO natural gas price decrease	C$0.50/GJ	11	0.12	11	0.12

[1] An opposite change in each of these variables will result in the opposite funds from operations and net income impacts.

2005 OUTLOOK

Financial Forecast

For the 2005 year, we are forecasting annual Syncrude production to range between 80 and 86 million barrels, or 28.4 to 30.5 million barrels net to the Trust based on its 35.49 per cent interest. The upper end of the range reflects strong operational performance at Syncrude and one planned turnaround of Coker 8-2, while the low end of the range incorporates the possibility of a second turnaround of Coker 8-1. Coker 8-1 was turned around late in 2003, and is scheduled for turnaround in early 2006. However, given that there is uncertainty around timing, the potential for a 2005 turnaround of Coker 8-1 does exist.

Our production estimate, for purposes of forecasting our 2005 financial results, is based on annual Syncrude production of 83 million barrels, or 29.5 million barrels net to the Trust. This estimate, as of February 21, 2005, reflects strong production comparable to actual production in 2004 with a planned turnaround of Coker 8-2 and unplanned repairs on Hydrogen Plant 9-3, which experienced an unsuccessful start-up following a maintenance turnaround in January of 2005. We estimate the coker turnaround, which commenced on February 11, 2005, will impact Syncrude production by approximately four million barrels based on historical coker turnaround activity.

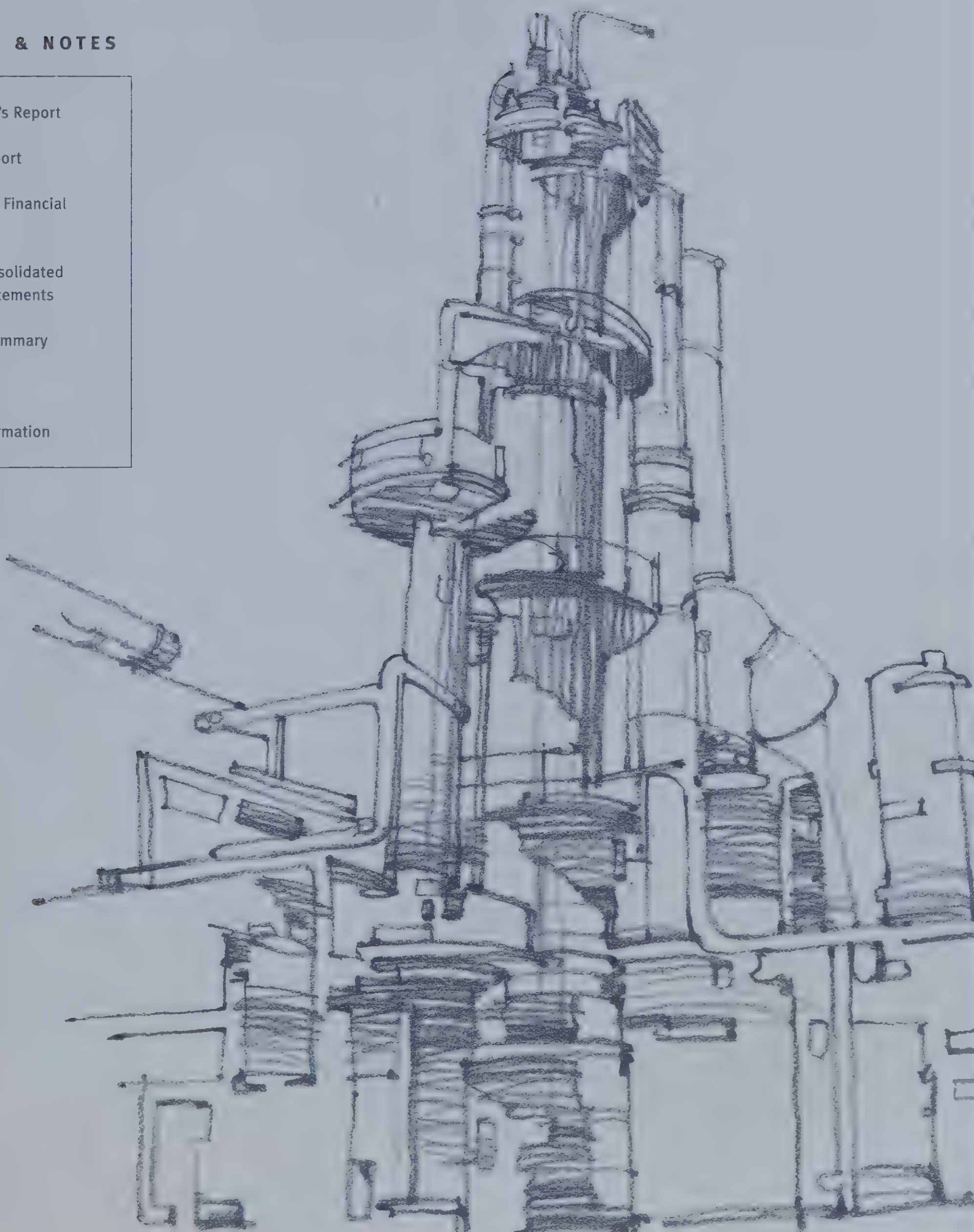
Assuming oil prices will average US$40 per barrel WTI in 2005, utilizing a foreign currency exchange rate of $0.80 US/Cdn with a differential from Canadian dollar WTI of $2.50 per barrel to account for quality and location differences, together with our production estimate, results in net revenues of approximately $1.4 billion in 2005. Operating costs before purchased energy are estimated at $15.51 per barrel, or $457 million. Purchased energy costs are anticipated to total $153 million, or $5.21 per barrel, assuming a natural gas cost of $7.00 per GJ. Utilizing these key assumptions, funds from operations are estimated at $580 million, or $6.29 per Unit, which combined with our available credit facilities and DRIP proceeds are expected to be adequate sources of financing to fund our capital expenditure program.

We have estimated our share of Syncrude's 2005 capital expenditures to total approximately $691 million, of which approximately $449 million will be directed to the Stage 3 expansion. Non-production costs, which include costs related to the capital program and are expensed, are expected to total approximately $85 million for 2005.

Income Trusts to be added to S&P/TSX Composite Index On January 26, 2005 Standard & Poor's ("S&P") announced that it intends to include income trusts in the S&P/TSX Composite Index. This change is anticipated to occur by mid-2005 following consultation with various stakeholders. Canadian Oil Sands strongly supports this move which we believe will result in a more representative Canadian "equity" asset class. Previously, a number of institutional investors were precluded from investing in income trusts since such trusts were not included in the broad equity index against which they were benchmarked.

Montreal Exchange Put and Call Options Effective February 28, 2005 put and call options on Canadian Oil Sands' Units will be listed on the Montreal Exchange under the symbol COS-U. Canadian Oil Sands is the first trust to have such options listed on this exchange. We expect the listing to increase the visibility and liquidity of our Units.

STATEMENTS & NOTES



MANAGEMENT'S REPORT

Management is responsible for the information contained in this annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and include amounts based on management's informed judgments and estimates. Where alternative accounting methods exist, management has chosen those it deems to be the most appropriate based on Canadian Oil Sands' operations. The financial and operating information included in this annual report is consistent with that contained in the consolidated financial statements in all material respects.

To assist management in fulfilling its responsibilities, systems of accounting and internal controls are maintained to provide reasonable, but not absolute, assurance that financial information is reliable and accurate, and that assets are adequately safeguarded. In addition, Canadian Oil Sands has in place a code of ethics that applies to all of its employees.

PricewaterhouseCoopers LLP, Chartered Accountants, appointed annually by the Unitholders to serve as Canadian Oil Sands' external auditors, have audited the consolidated financial statements and conducted a review of accounting and internal controls to the extent required under Canadian generally accepted auditing standards. They have performed such tests as they deemed necessary to enable them to express an opinion on these financial statements. Canadian Oil Sands also engages independent reserve evaluators to conduct independent evaluations of its crude oil reserves. The external auditors and reserve evaluators have unrestricted access to Canadian Oil Sands, the Audit Committee and the Board of Directors.

The Board of Directors has appointed a four-person Audit Committee, consisting of directors who are neither employees nor officers of Canadian Oil Sands and all of whom are independent. It meets regularly with management and external auditors to discuss controls over the financial reporting process, auditing and other financial reporting matters. In addition, the Audit Committee recommends the appointment of Canadian Oil Sands' external auditors and appoints the independent reserve evaluators. The Audit Committee meets at least quarterly with management and the external auditors to review and approve interim financial statements prior to their release and recommends them to the Board of Directors for their approval. Annually it reviews and approves Canadian Oil Sands' annual financial statements, Management's Discussion and Analysis, Annual Information Form, Management Information Circular, and annual reserves estimates, and recommends its approval of such documents to the Board of Directors. The Board of Directors has approved the consolidated financial statements and the Management's Discussion and Analysis based on the recommendation of the Audit Committee.

Marcel R. Coutu	Allen R. Hagerman, FCA
President & Chief Executive Officer	Chief Financial Officer
February 22, 2005	February 22, 2005

AUDITORS' REPORT

To the Unitholders of
Canadian Oil Sands Trust

We have audited the consolidated balance sheets of Canadian Oil Sands Trust as at December 31, 2004 and 2003 and the consolidated statements of income and Unitholders' equity and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
January 28, 2005

CONSOLIDATED STATEMENTS OF INCOME AND UNITHOLDERS' EQUITY

For the years ended December 31 ($ millions, except per Trust unit amounts)	2004	2003 Restated – See Note 3(a)
Syncrude Sweet Blend revenues	**$ 1,396.9**	$ 967.8
Transportation and marketing expense	**(44.9)**	(35.8)
	1,352.0	932.0
Expenses		
Operating	**600.5**	514.9
Non-production	**47.9**	38.2
Crown royalties (Note 18)	**18.0**	11.9
Administration	**8.8**	9.1
Insurance	**9.4**	7.4
Interest, net (Note 15)	**95.3**	67.8
Depreciation, depletion and accretion	**171.9**	92.5
Foreign exchange gain	**(79.7)**	(135.1)
Income and Large Corporations Tax (Note 12)	**(2.0)**	17.4
Future income tax recovery (Note 12)	**(27.3)**	(2.2)
	842.8	621.9
Net income	**$ 509.2**	$ 310.1
Unitholders' equity, beginning of year		
As previously reported	**$ 2,094.4**	$ 956.5
Change in accounting policies (Note 3)	**8.5**	6.1
As restated	**2,102.9**	962.6
Net income	**509.2**	310.1
Issue of Trust units (Note 13)	**203.3**	999.3
Unitholder distributions (Note 16)	**(180.4)**	(169.9)
Contributed surplus (Note 14 (a))	**0.9**	0.8
Unitholders' equity, end of year	**$ 2,635.9**	$ 2,102.9
Weighted-average Trust Units	**89.0**	79.7
Trust Units, end of year	**91.4**	87.2
Net income per Trust Unit		
Basic and diluted (Note 13 (c))	**$ 5.72**	$ 3.89

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	2004	2003
		Restated – See Note 3(a)
Assets		
Current assets		
Cash and short-term investments	$ 17.8	$ 16.7
Accounts receivable	145.7	116.2
Inventories (Note 5)	57.1	57.4
Prepaid expenses	2.9	4.6
	223.5	194.9
Property, plant and equipment, net (Note 6)	4,794.8	4,023.0
Other assets		
Reclamation trust (Note 10)	21.0	16.6
Deferred financing charges, net	28.4	25.5
	49.4	42.1
	$ 5,067.7	$ 4,260.0
Liabilities and Unitholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 273.6	$ 246.6
Unit distribution payable	45.7	43.6
Current portion of employee future benefits (Note 7)	7.2	6.1
	326.5	296.3
Employee future benefits and other liabilities (Note 7)	91.9	87.6
Long-term debt (Note 9)	1,699.8	1,437.4
Asset retirement obligation (Note 10)	44.1	44.7
Deferred currency hedging gains (Note 11)	27.6	21.9
Future income taxes (Note 12)	241.9	269.2
	2,431.8	2,157.1
Unitholders' equity (Note 13)	2,635.9	2,102.9
	$ 5,067.7	$ 4,260.0

Commitments and Contingencies (Note 19)

See Notes to Consolidated Financial Statements.

Approved by the Board of Directors

Director

Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	2004	2003 Restated – See Note 3(a)
Cash provided by (used in)		
Operating activities		
Net income	$ 509.2	$ 310.1
Items not requiring outlay of cash		
Depreciation, depletion and accretion	171.9	92.5
Amortization	3.1	3.1
Foreign exchange on long-term debt	(89.2)	(147.2)
Future income tax recovery	(27.3)	(2.2)
Other	2.6	0.6
Net change in deferred items	5.5	15.9
Funds from operations	575.8	272.8
Change in non-cash working capital (Note 21 (a))	17.9	(51.0)
	593.7	221.8
Financing activities		
Issuance of medium term and senior notes (Note 9)	723.5	571.7
Net drawdown (repayment) of bank credit facilities (Note 9)	(371.9)	390.6
Unitholder distributions (Note 16)	(180.4)	(169.9)
Issuance of Trust units (Note 13)	203.3	999.3
Net change in deferred items	(4.2)	(16.0)
Change in non-cash working capital (Note 21 (a))	2.1	14.7
	372.4	1,790.4
Investing activities		
Acquisition of Syncrude working interests (Note 4)	–	(1,475.3)
Capital expenditures	(942.1)	(785.5)
Reclamation trust	(4.5)	(3.7)
Change in non-cash working capital (Note 21 (a))	(18.4)	39.0
	(965.0)	(2,225.5)
Increase (decrease) in cash and short-term investments	1.1	(213.3)
Cash and short-term investments, beginning of year	16.7	230.0
Cash and short-term investments, end of year	$ 17.8	$ 16.7
Supplemental Information		
Large Corporations and Income Tax paid	$ 14.2	$ 17.8
Interest charges paid	$ 86.4	$ 60.9

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts expressed in millions of dollars, except where otherwise noted)

1. STRUCTURE OF CANADIAN OIL SANDS TRUST

Canadian Oil Sands Trust (the "Trust") is an open-ended investment trust formed under the laws of the Province of Alberta in October 1995 pursuant to a trust indenture ("Trust Indenture") which has since been amended and restated. Computershare Trust Company of Canada is appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders ("Unitholders") of the units ("Units") in the Trust.

The Trust, through its wholly owned subsidiaries, owns a 35.49 per cent interest ("Working Interest") in the Syncrude Joint Venture ("Syncrude") which is involved in the mining and upgrading of bitumen from oil sands in Northern Alberta and operated by Syncrude Canada Ltd. ("Syncrude Canada").

2. SUMMARY OF ACCOUNTING POLICIES

Consolidation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("GAAP") and include the accounts of the Trust and its subsidiaries (collectively, "Canadian Oil Sands"). The activities of the Syncrude Joint Venture are conducted jointly with others and, accordingly, these financial statements reflect only the proportionate interest in such activities, which include the production, operating costs, non-production costs, property, plant and equipment capital expenditures, inventories, employee future benefits and other liabilities, asset retirement obligation, and associated amounts payable. Substantially all other activities and balances in these financial statements, including sales, are applicable directly to the activities of Canadian Oil Sands.

Cash and short-term investments

Investments with maturities of less than three months at purchase are considered to be cash equivalents and are recorded at cost, which approximates market value.

Property, Plant and Equipment

Property, plant and equipment assets are recorded at cost and include the costs of acquiring the Working Interest and subsequent additions to property, plant and equipment ("PP&E"). Also included in PP&E is the estimated fair value of Canadian Oil Sands' asset retirement obligation (see asset retirement obligation accounting policy note). Repairs and maintenance costs are expensed in the period incurred. Proceeds from the sale of PP&E are deducted from the capital base without recognition of a gain or loss.

PP&E are depreciated and depleted on the unit-of-production method based on estimated proved and probable reserves. For purposes of the depreciation and depletion provision, capital costs include future capital costs expected to be necessary in the mining, extraction and upgrading process to recover the estimated proved and probable reserves.

An asset impairment test is applied to Canadian Oil Sands' PP&E to ensure that the capitalized costs do not exceed management's estimate of future undiscounted revenues from proved reserves, less operating expenses, asset retirement costs, Crown royalties, and general and administrative expenses.

Inventories

Product inventories are valued at the lower of the average cost of production for the period and their net realizable value. Materials and supplies inventories are valued at the lower of average cost and replacement cost.

Asset retirement obligation

The estimated fair value of the Trust's 35.49 per cent share of Syncrude's retirement obligations pertaining to PP&E is recognized on the Trust's Consolidated Balance Sheet. Syncrude's reclamation obligations relate to the site restoration of each mine site, of which the discounted full amount of the liability is recorded upon initial land disturbance. The fair value is determined by estimating the timing and amounts of the future reclamation expenditures, and discounting the expenditures using a credit adjusted risk free rate applicable to the Trust. An obligation is recognized when a reasonable estimate of the amount and timing of the reclamation expenditures can be determined. The asset retirement cost is equal to the estimated fair value of the asset retirement obligation, and is capitalized as part of the Trust's PP&E. These capital assets are depreciated using the unit-of-production method. The obligation is accreted based on the Trust's applied discount rate. The depreciation expense and accretion expense are reflected in the Trust's depreciation, depletion and accretion expense ("DD&A") in consolidated net income.

Actual costs are charged against the accumulated obligation when incurred.

Derivative financial instruments

Canadian Oil Sands may enter into derivative financial instrument contracts such as foreign currency exchange rate, crude oil and natural gas price contracts to hedge fluctuations in exchange rates, and the prices of crude oil and natural gas. Canadian Oil Sands may also enter into interest rate swap agreements to manage its interest rate risk.

Pursuant to Canadian Oil Sands' risk management policies, relationships between hedging instruments and hedged items and the strategy for undertaking the hedge transaction are documented. Canadian Oil Sands records the derivative contract as a hedge for accounting purposes, when at the time of initiating the contract, it is identified as a hedge of a specific transaction and, at both the inception of the contract and on an ongoing basis, Canadian Oil Sands assesses the derivative instrument as effective in offsetting cash flows of the hedged item. Canadian Oil Sands uses a statistical methodology called correlation analysis to test effectiveness of its crude oil and foreign exchange financial instruments on a quarterly basis. For its interest rate swaps which qualify as hedges, an effectiveness test is not required each quarter as long as the critical terms of the swap contract continue to match the underlying debt instrument. Canadian Oil Sands reviews the critical terms of the swap contract against the terms of the debt each quarter.

If a derivative contract cannot be designated as a hedge under Canadian GAAP or the hedge is no longer effective, then mark-to-market accounting is used, whereby the fair value of the contract is recorded on the balance sheet as an asset or liability. Subsequent changes in the fair value of the asset or liability are recognized in other income, which is included in net interest expense on the income statement, when those changes occur.

Gains and losses on hedge contracts which qualify for hedge accounting, are recognized in net income and cash flows when the related revenues, costs, interest expense and cash flows are recognized. Crude oil and foreign currency hedging gains and losses are included in Syncrude Sweet Blend ("SSB") revenues as incurred. As natural gas is used in the production of SSB, any natural gas hedging gains and losses are included in operating expenses. For interest rate swaps that qualify for hedge accounting, any gains or losses on the swaps are included in net interest expense as incurred.

Revenues

Revenues from the sale of SSB are recorded when title passes from Canadian Oil Sands to its customer. Revenues are recorded inclusive of hedging gains and losses from foreign currency exchange rate and crude oil price contracts.

Employee future benefits

Canadian Oil Sands accrues its obligations as a joint venture owner in respect of Syncrude Canada's employee benefit plans and the related costs, net of plan assets. The cost of employee pension and other retirement benefits is actuarially determined using the projected benefit method based on length of service and reflects Canadian Oil Sands' best estimate of the expected performance of the plan investment, salary escalation factors, retirement ages of employees and future health care costs. The expected return on plan assets is based on the fair value of those assets. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service life of active employees ("EARSL") at the date of amendment. The excess of any net actuarial gain or loss exceeding 10 per cent of the greater of the benefit obligation and fair value of the plan assets is amortized over the EARSL (Note 7(a)).

Future income taxes

Canadian Oil Sands follows the liability method of accounting for income taxes. Under this method, future income taxes of operating corporations are calculated as the difference between the accounting and income tax basis of an asset or liability, referred to as temporary differences, tax effected using substantively enacted income tax rates. Future income tax balances recorded on the Consolidated Balance Sheet are adjusted to reflect changes in temporary differences and income tax rates with the adjustments being recognized in net income in the period that the changes occur.

Stock-based compensation

Canadian Oil Sands recognizes stock-based compensation expense in its Consolidated Statement of Income and Unitholders' Equity for all trust unit options ("options") granted during the year, with a corresponding increase to contributed surplus in Unitholders' Equity. Canadian Oil Sands determines compensation expense based on the estimated fair values of the options at the time of grant, the cost of which is recognized in net income over the vesting periods of the options.

As an owner in the Syncrude Joint Venture, Canadian Oil Sands also records its share of costs for Syncrude's stock-based compensation program. Syncrude's plan has incentive phantom share units ("phantom units") which require settlement by cash payments. During the vesting period, compensation expense is recognized using the graded vesting approach when the value of the phantom units exceeds the award value. Canadian Oil Sands' share of the change in value of the phantom units is recognized in operating expense in the year the change occurs.

Foreign currency translation

Canadian Oil Sands receives a portion of its revenues, incurs various expenses, and issues some debt in U.S. dollars, which result in monetary assets and liabilities denominated in U.S. dollars. These U.S. denominated balances are translated to Canadian dollars at exchange rates in effect at the end of the period, with the resulting gain or loss being recorded in the income statement. Translation gains and losses on U.S. denominated long-term debt are recorded as unrealized and excluded from funds from operations. All other translation gains and losses, which relate to the translation of U.S. denominated cash, accounts receivable and accounts payable, are classified as realized since they are settled in less than one year.

Net income per Trust Unit

Canadian Oil Sands applies the treasury stock method to determine the dilutive impact, if any, of options assuming they were exercised in a reporting period. The treasury stock method assumes that all proceeds received by the Trust when options are exercised would be used to purchase Units at the average market price during the period.

Measurement uncertainty

The preparation of the consolidated financial statements under Canadian GAAP requires management personnel to make estimates and assumptions for many financial statement items based on their best estimate and judgment. Significant judgments and estimates relate to depreciation, depletion, the impairment test and asset retirement obligation costs as they are based on reserve engineering studies, environmental studies and future price and cost estimates, which by their nature, are highly subjective. The values of pension and other benefit plan accrued obligations and plan assets and the amount of pension cost charged to net income depend on certain actuarial and economic assumptions, which by their nature are subject to measurement uncertainty. The calculation of future income tax is based on assumptions, which are subject to uncertainty as to the timing and at which tax rates temporary differences are expected to reverse. Accordingly, actual results may differ from all of these estimated amounts as future events occur.

3. CHANGE IN ACCOUNTING POLICIES

a) Asset Retirement Obligations

Effective January 1, 2004, Canadian Oil Sands adopted the new accounting standard of the Canadian Institute of Chartered Accountants ("CICA") for asset retirement obligations (CICA Handbook Section 3110). Upon adoption, Canadian Oil Sands recognized an asset retirement obligation and a corresponding increase to PP&E equal to the estimated fair value of the Trust's 35.49 per cent share of Syncrude's retirement obligations. Syncrude's reclamation obligations relate to the site restoration of each mine site, of which the discounted full amount of the liability is recorded upon initial land disturbance. At December 31, 2004, the Trust's reclamation obligation represents the liability on the Base, North and Aurora North mines only. Prior to the adoption of this standard, the future site reclamation liability was accrued on a unit-of-production basis based on estimated total future site reclamation costs and proved reserves.

The standard has been adopted retroactively, with restatement of prior year's balances. The impact on the comparative balances was the following:

December 31		2003
Consolidated Balance Sheet		
Increase property, plant, and equipment, net	$	0.1
Decrease asset retirement obligation		(12.8)
Increase future income tax liability		4.4
Increase retained earnings		8.5

The impact on net income in 2003 was an increase of $2.2 million. The increase to net income was comprised of a decrease to the future site reclamation expense recorded under the former accounting policy, partially offset by an increase to depreciation expense and accretion expense as per the new requirements. In 2004, opening retained earnings was increased by $8.5 million and net income decreased by $2.2 million. The addition to PP&E is being depreciated in the same manner as the Trust's existing PP&E. The liability is being accreted based on the discount rates used with the accretion expense recorded in net income. These impacts are reflected in the Trust's DD&A expense on the income statement.

b) Hedge Accounting

Effective January 1, 2004, Canadian Oil Sands adopted new guidelines for hedge accounting in accordance with the CICA's Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 establishes certain conditions for when hedge accounting may be applied. Under AcG-13, the Trust is continuing to apply hedge accounting for its crude oil and foreign currency hedges, which results in the hedging settlement gains or losses being included in net income in the same period the hedged items are settled. Therefore, there is no impact to the Trust's financial results related to those hedge positions as a result of adopting AcG-13.

However, the Trust's interest rate swap positions that were in existence at January 1, 2004 do not qualify as hedges under AcG-13, and therefore, the Trust has recorded these positions at the fair market values as of January 1, 2004, which resulted in a deferred gain of approximately $4.9 million. The fair market value was recorded as an increase to other assets and other liabilities. The asset balance is re-assessed each quarter to determine its current fair market value and any changes in the valuation are recorded in net income. In 2004, the change in the fair value of the interest rate swaps was a decrease of approximately $1.7 million. The loss has been recorded as a reduction to other income and is included in net interest expense on the income statement. The liability balance is being amortized as the swap contracts settle. The swap contracts expire on May 15, 2007. In accordance with AcG-13, prior period financial statements have not been restated.

c) Stock-based compensation

During the third quarter of 2003, Canadian Oil Sands retroactively adopted the fair-value method of accounting for stock-based compensation related to options pursuant to transitional rules for stock-based compensation approved by the CICA. Canadian Oil Sands' prior period financial statements have not been restated.

For the year ended December 31, 2003, compensation costs of $0.6 million were included as Administration expenses in Canadian Oil Sands' net income, with a corresponding increase to contributed surplus included in Unitholders' Equity. Stock-based compensation expense of $0.2 million relating to options granted in 2002 has been charged to opening retained earnings in 2003, with a corresponding increase to contributed surplus.

4. ACQUISITION OF SYNCRUDE WORKING INTERESTS

a) On February 28, 2003, Canadian Oil Sands closed the acquisition with EnCana Corporation ("EnCana") to purchase an indirect 10 per cent Working Interest in Syncrude for approximately $1.05 billion cash, with an effective transaction date of February 1, 2003. At this time, Canadian Oil Sands also obtained an option to purchase, under similar terms and conditions, EnCana's remaining 3.75 per cent interest in Syncrude and a six per cent gross overriding royalty ("GORR") on another 1.25 per cent indirect Syncrude interest in certain leases held by a third party independent oil and gas company. This option was exercised in June 2003.

b) On July 10, 2003, Canadian Oil Sands completed its purchase of EnCana's remaining interest in Syncrude and GORR for approximately $430 million cash, with an effective transaction date of February 1, 2003.

The acquisitions have been accounted for as a purchase of assets in accordance with Canadian GAAP. The purchase price, including the working capital adjustments and purchase price adjustments, was allocated to the assets and liabilities as follows:

	February acquisition(1)	July acquisition(2)	Total 2003 acquisitions
Net assets and liabilities assumed			
Property, plant and equipment	$ 1,403.8	$ 453.3	$ 1,857.1
Working capital deficiency	(29.9)	(0.5)(3)	(30.4)
Employee future benefits and other liabilities	(44.1)	(16.1)	(60.2)
Asset retirement obligation	(15.3)	(6.8)	(22.1)
Future income taxes	(267.0)	–(4)	(267.0)
	$ 1,047.5	$ 429.9	$ 1,477.4
Consideration			
Cash	$ 1,041.0	$ 429.9	$ 1,470.9
Costs associated with acquisition	6.5	–(5)	6.5
	$ 1,047.5	$ 429.9	$ 1,477.4

(1) Acquisition of 10 per cent working interest from EnCana, which closed February 28, 2003.

(2) Acquisition of 3.75 per cent working interest and six per cent GORR from EnCana, pursuant to the option agreement.The acquisition closed July 10, 2003.

(3) Included in the working capital deficiency was cash acquired of approximately $2.1 million.

(4) There was no future income tax as a result of the 3.75 per cent acquisition in 2003 as the working interest was held in a partnership, and owned by a trust.

(5) Costs associated with the acquisition were not material as most of the costs were already incurred in the 10 per cent working interest acquisition.

5. INVENTORIES

	2004	2003
Materials and supplies	$ 45.1	$ 42.2
Product and linefill	12.0	15.2
	$ 57.1	$ 57.4

6. PROPERTY, PLANT AND EQUIPMENT, NET

	Cost	Accumulated Depreciation and Depletion	Net Book Value
December 31, 2004			
Property, plant and equipment	$ 5,438.9	$ 644.5	$ 4,794.4
Other capital assets	0.8	0.4	0.4
	$ 5,439.7	$ 644.9	$ 4,794.8
December 31, 2003			
Property, plant and equipment	$ 4,496.8	$ 474.4	$ 4,022.4
Other capital assets	0.8	0.2	0.6
	$ 4,497.6	$ 474.6	$ 4,023.0

Total DD&A expense is comprised of the following amounts for the year ended December 31:

	2004	2003
Depreciation and depletion expense	$ 170.3	$ 91.7
Accretion expense	1.6	0.8
	$ 171.9	$ 92.5

In 2004, the Trust depreciated and depleted its PP&E based on proved plus probable reserves. The change in estimate in 2004 to include probable reserves significantly increased the depreciation and depletion ("D&D") rate in 2004 compared to 2003 as all Stage 3 expenditures, including future development costs, were included in the 2004 D&D rate. In 2003, only proved reserves and the future development costs related to the development of those reserves were included in the D&D rate calculation. In 2003, the D&D rate was calculated at the beginning of the year, and then adjusted in March and July 2003 to reflect the 10 per cent and 3.75 per cent working interest acquisitions. Total Stage 3 expansion expenditures of approximately $0.5 billion were excluded from the depreciable net asset base at January 1, 2003 in determining the D&D rate for 2003, and adjusted at March 1 and July 1 to reflect the working interest acquisitions.

7. EMPLOYEE FUTURE BENEFITS AND OTHER LIABILITIES

	2004	2003
Employee future benefits (a)	$ 93.3	$ 90.6
Other	6.0	3.7
	$ 99.3	$ 94.3
Less current portion comprised of:		
Other (included in accounts payable and accrued liabilities)	(0.2)	(0.6)
Employee future benefits	(7.2)	(6.1)
	$ 91.9	$ 87.6

a) Employee future benefits

Syncrude Canada has a defined benefit and two defined contribution plans providing pension benefits, and other retirement and post-employment benefit plans covering most of its employees. Post-employment benefits include certain health care and life insurance benefits for retirees, their beneficiaries and covered dependants.

Defined benefit plan

Syncrude measures its accrued benefit obligation and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2003, and the next required valuation will be as of December 31, 2006.

Canadian Oil Sands' share of Syncrude Canada's defined benefit plan accrued liability, based on its 35.49 per cent ownership at December 31 for each of 2004 and 2003, is comprised of its share of Syncrude Canada's accrued benefit obligation, partially offset by its share of Syncrude Canada's defined benefit plan assets as follows:

	Pension Benefit Plan		Other Benefit Plans		Total	
	2004	2003	**2004**	2003	**2004**	2003
Accrued benefit obligation:						
Balance – Beginning of year	**$ 351.2**	$ 184.9	**$ 33.3**	$ 17.9	**$ 384.5**	$ 202.8
Acquired [1]	**–**	117.0	**–**	11.3	**–**	128.3
Current service cost	**14.8**	12.7	**0.9**	0.8	**15.7**	13.5
Interest cost	**21.2**	19.7	**2.0**	1.9	**23.2**	21.6
Transferred in	**2.4**	–	**–**	–	**2.4**	–
Benefits paid	**(11.6)**	(10.4)	**(1.2)**	(1.1)	**(12.8)**	(11.5)
Actuarial loss	**33.8**	27.3	**3.0**	2.5	**36.8**	29.8
Balance – End of year	**$ 411.8**	$ 351.2	**$ 38.0**	$ 33.3	**$ 449.8**	$ 384.5
Fair value of plan assets:						
Actuarial fair value – Beginning of year	**$ 213.1**	$ 111.1	**$ –**	$ –	**$ 213.1**	$ 111.1
Acquired [1]	**–**	70.3	**–**	–	**–**	70.3
Actual return on plan assets	**22.8**	32.7	**–**	–	**22.8**	32.7
Employer contributions	**20.0**	8.9	**–**	–	**20.0**	8.9
Contributions – transfers	**2.4**	–	**–**	–	**2.4**	–
Benefits paid	**(11.0)**	(9.9)	**–**	–	**(11.0)**	(9.9)
Actuarial fair value – End of year	**247.3**	213.1	**–**	–	**247.3**	213.1
Funded status – Plan deficit	**(164.5)**	(138.1)	**(38.0)**	(33.3)	**(202.5)**	(171.4)
Unamortized net actuarial loss [2]	**99.8**	74.0	**8.2**	5.4	**108.0**	79.4
Unamortized past service costs [2]	**1.2**	1.4	**–**	–	**1.2**	1.4
Accrued benefit liability	**$ (63.5)**	$ (62.7)	**$ (29.8)**	$ (27.9)	**$ (93.3)**	$ (90.6)

1 Canadian Oil Sands assumed the employee benefit obligation relating to the additional 13.75 per cent working interest acquired from EnCana during 2003.

2 Amortized over the expected average remaining service lives of employees covered by the plan, generally 13 years.

The asset allocation for Syncrude Canada's plan assets as of December 31 was as follows:

	Percentage of plan assets	
	2004	2003
Equity securities	70%	72%
Debt securities	30	28
	100%	100%

Elements of defined benefit costs recognized in the year

	Pension Benefit Plan		Other Benefit Plans		Total	
	2004	2003	2004	2003	2004	2003
Current service cost	$ 14.8	$ 11.5	$ 0.9	$0.8	$ 15.7	$ 12.3
Interest cost	21.2	19.7	2.0	1.9	23.2	21.6
Actual return on plan assets	(22.8)	(32.7)	–	–	(22.8)	(32.7)
Actuarial loss	33.8	27.3	3.0	2.5	36.8	29.8
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs	$ 47.0	$ 25.8	$ 5.9	$ 5.2	$ 52.9	$ 31.0
Adjustments to recognize the long-term nature of employee future benefit costs:						
Difference between expected return and actual return on plan assets	4.4	16.4	–	–	4.4	16.4
Difference between actuarial loss recognized for year and actual actuarial loss on accrued benefit obligation for year	(30.1)	(23.6)	(2.8)	(2.4)	(32.9)	(26.0)
Difference between amortization of past service costs for year and actual plan amendments for year	0.1	0.2	–	–	0.1	0.2
	(25.6)	(7.0)	(2.8)	(2.4)	(28.4)	(9.4)
Defined benefit costs recognized in net income	$ 21.4	$ 18.8	$ 3.1	$ 2.8	$ 24.5	$ 21.6

Total cash payments

Canadian Oil Sands' share of Syncrude's total cash payments for employee future benefits for 2004, consisting of cash contributed by Syncrude to its funded pension plans, cash to fund pension payments in excess of registered plan limits, cash payments directly to beneficiaries for its unfunded other benefit plans, and cash contributed to its defined contribution plans, was $23.5 million (2003 – $10.6 million), based on its 35.49 per cent ownership in 2004, and varying working interests in 2003.

Significant assumptions

The significant assumptions adopted in measuring Syncrude Canada's accrued benefit obligations are as follows:

	Pension Benefit Plan		Other Benefit Plans	
	2004	2003	**2004**	2003
Accrued benefit obligation as of December 31:				
Discount rate	**5.75%**	6.0%	**5.75%**	6.0%
Rate of compensation increase	**4.0%**	4.0%	**4.0%**	4.0%
Benefit costs for years ended December 31:				
Discount rate	**6.0%**	6.5%	**6.0%**	6.5%
Expected long-term rate of return on plan assets	**8.5%**	9.0%	**n/a**	n/a
Rate of compensation increase	**4.0%**	4.0%	**4.0%**	4.0%

For measurement purposes, a 10 per cent annual rate of increase in the cost of supplemental health care benefits was assumed for 2004, decreased by 0.5 per cent each year thereafter to a 5 per cent ultimate rate. In addition, annual rate increases of 3 per cent in Alberta health care premiums and 4 per cent in dental rates were used.

Sensitivity Analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one per cent change in assumed health care cost trend rates would have the following effects on Canadian Oil Sands' results for 2004, based on its 35.49 per cent working interest in Syncrude:

	Increase	Decrease
Total of current service and interest cost	$ 0.4	$ (0.4)
Accrued benefit obligation	$ 4.3	$ (3.8)

Defined contribution plans

Canadian Oil Sands' share of the total expense, based on its 35.49 per cent working interest during 2004 and varying working interests during 2003, for Syncrude Canada's defined contribution pension plans for 2004 and 2003 was $1.7 million and $1.4 million, respectively.

8. BANK CREDIT FACILITIES

	Credit facility
Extendible revolving term facility (a)	$ 20.0
Line of credit (b)	25.0
Operating credit facility (c)	225.0
Operating credit facility (d)	415.0
	$ 685.0

a) The $20 million extendible revolving term facility is a one-year facility with a two-year term out, expiring June 28, 2005. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

b) The $25 million line of credit is a one-year revolving letter of credit facility. Letters of credit drawn on the facility mature April 30th each year and are automatically renewed, unless cancelled by Canadian Oil Sands or by the financial institution providing the facility within 60 days prior to expiry. Letters of credit on this facility bear interest at a credit spread.

Letters of credit of approximately $38 million have been written against the extendible revolving term facility and line of credit as disclosed in Note 20.

c) The $225 million operating facility is an extendible 364-day revolving tranche with a two-year term out, expiring March 22, 2006. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

d) The $415 million operating credit facility consists of a $138 million extendible 364-day revolving tranche with a two-year term out, expiring June 24, 2005, and a $277 million three-year extendible term tranche, expiring July 2, 2007. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

e) Each of the Trust's credit facilities is unsecured. These credit agreements contain typical covenants relating to the restriction on Canadian Oil Sands' ability to sell all or substantially all of its assets or to change the nature of its business. In addition, Canadian Oil Sands has agreed to maintain its senior debt to book capitalization at an amount less than 0.55 to 1.0, to maintain total debt-to-total book capitalization at an amount less than 0.60 to 1.0, and restrict distributions by way of the trust royalty payments from the Trust's operating subsidiary, Canadian Oil Sands Limited ("COSL"), if COSL's credit ratings fall below investment grade.

As at December 31, 2004 $18.7 million of the operating credit facilities was drawn, and is included in long-term debt on the Consolidated Balance Sheet.

9. LONG-TERM DEBT

	2004	2003
3.95% medium term notes due January 15, 2007 (a)	$ 175.0	$ –
Floating rate medium term notes due January 15, 2007 (a)	20.0	–
7.625% Senior Notes due May 15, 2007 (b)	84.2	90.4
5.75% medium term notes due April 9, 2008 (c)	150.0	150.0
5.55% medium term notes due June 29, 2009 (d)	200.0	–
4.8% Senior Notes due August 10, 2009 (e)	300.9	–
5.8% Senior Notes due August 15, 2013 (f)	361.1	387.7
7.9% Senior Notes due September 1, 2021 (g)	300.9	323.1
8.2% Senior Notes due April 1, 2027 (h)	89.0	95.6
Credit facilities drawn, excluding letters of credit (Note 8)	18.7	390.6
	$ 1,699.8	$ 1,437.4

All of Canadian Oil Sands' medium term notes and Senior Notes are unsecured, rank pari passu with other senior unsecured debt of COSL, and contain certain covenants which place limitations on the sale of assets and the granting of liens or other security interests. The medium term notes are guaranteed by the Trust.

a) 3.95% Medium Term Notes and Floating Rate Medium Term Notes

On January 15, 2004 COSL issued $20 million of floating rate unsecured medium term notes as well as $175 million of 3.95% unsecured medium term notes. The fixed interest rate debt was swapped into floating rates pursuant to interest rate swap agreements (Note 17(b)(ii)). Both the floating rate and 3.95% medium term notes mature on January 15, 2007. Interest on the 3.95% notes is payable semi-annually on January 15 and July 15. Interest on the floating rate notes is payable quarterly on January 15, April 15, July 15 and October 15.

b) 7.625% Senior Notes

On May 20, 1997 COSL issued US$70 million of 7.625% Senior Notes, maturing May 15, 2007. Interest rate swap agreements (Note 17(b)(i)) were entered into to swap the interest rate to a 5.95% fixed rate U.S. dollar payment. Interest is payable on the notes semi-annually on May 15 and November 15.

c) 5.75% Medium Term Notes

On April 8, 2003 COSL issued $150 million of 5.75% unsecured medium term notes, maturing April 9, 2008. Interest is payable on the notes semi-annually on April 9 and October 9.

d) 5.55% Medium Term Notes

On June 29, 2004 COSL issued $200 million of 5.55% unsecured medium term notes, maturing June 29, 2009. Interest is payable on the notes semi-annually on June 29 and December 29.

e) 4.8% Senior Notes

On August 9, 2004 COSL issued US$250 million of 4.8% Senior Notes, maturing August 10, 2009. Interest is payable on the notes semi-annually on February 10 and August 10.

f) 5.8% Senior Notes

On August 6, 2003 COSL issued US$300 million of 5.8% Senior Notes, maturing August 15, 2013. Interest is payable on the notes semi-annually on February 15 and August 15.

g) 7.9% Senior Notes

On August 24, 2001 COSL issued US$250 million of 7.9% Senior Notes, maturing September 1, 2021. Interest is payable on the notes semi-annually on March 1 and September 1.

h) 8.2% Senior Notes

On April 4, 1997 COSL issued US$75 million of 8.2% Senior Notes, maturing April 1, 2027, and retired US$1.05 million during 2000. Interest is payable on the notes semi-annually on April 1 and October 1.

i) Future minimum payments payable under long-term debt are as follows:

2006 [1]	$	18.7
2007		279.2
2008		150.0
2009		500.9
Later years		751.0
	$	1,699.8

1 There are no debt repayments required in 2005. Under the current terms, Canadian Oil Sands' outstanding credit facilities at December 31, 2004 will be payable in 2006.

10. ASSET RETIREMENT OBLIGATION AND RECLAMATION TRUST

		2004		2003
Asset retirement obligation – Beginning of year	$	**44.7**	$	45.0
Liabilities settled		**(2.2)**		(1.1)
Accretion expense		**1.6**		0.8
Asset retirement obligation – End of year	$	**44.1**	$	44.7

The Trust and each of the other owners of Syncrude are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Joint Venture on abandonment. Effective January 1, 2004, the Trust retroactively adopted the new standard of the CICA regarding the accounting for such environmental obligations as explained in Note 3(a). The total undiscounted estimated cash flows required to settle the Trust's share of the Syncrude obligation is $275 million (2003 – $277 million), which have been discounted using a credit-adjusted risk free rate of 6.75%. The Trust estimates these expenditures will be made over approximately the next 45 years, with the majority of the expenditures not being incurred for another 30 years when reclamation expenditures on the Aurora North mine are expected to be incurred.

Syncrude's upgrader facilities have indeterminate useful lives. Therefore, the fair values of the related asset retirement obligations cannot be reasonably determined. Also, the timing and amount of the reclamation expenditures, if any, related to Syncrude's sulphur blocks are not determinable at the present time. The asset retirement obligations pertaining to the upgrader facilities and the sulphur blocks will be recognized in the year in which the settlement amounts and dates can be reasonably estimated.

The reclamation expenditures will be funded from the Trust's funds from operations and from the Trust's mining reclamation trust accounts. The Trust paid $2.2 million in 2004 (2003 – $1.1 million) for its share of Syncrude's reclamation expenditures. The Trust deposits $0.1322 per barrel of production attributable to its 35.49 per cent working interest to mining reclamation trusts established for the purpose of funding the operating subsidiaries' share of environmental and reclamation obligations. Mining reclamation trust accounts for the 13.75 per cent Working Interest the Trust acquired in 2003 did not exist prior to the Trust's acquisition. As at December 31, 2004, including interest earned on the accounts, the balance of the mining reclamation trust accounts was $21 million.

In addition, the Trust has posted letters of credit with the Province of Alberta in the amount of $38 million (2003 – $31 million) to secure its pro rata share of the ultimate reclamation obligations of the Syncrude Joint Venture participants.

11. DEFERRED CURRENCY HEDGING GAINS

Canadian Oil Sands is exposed to fluctuations in the U.S.-Canadian currency exchange rate. In 1996, Canadian Oil Sands entered into currency hedging contracts to fix the exchange rate in future years. During 1999, Canadian Oil Sands unwound various positions and exchanged the resulting gain for adjustments to other existing currency contracts. For accounting purposes, the gain will be recognized as revenue over the period 2006 to 2016, which is when the hedging contracts would have expired had they not been unwound (Note 17(a)). During 2004, Canadian Oil Sands received payments totalling $5.7 million (2003 – $5.4 million) related to the unrecognized gain resulting in a cumulative deferral of $27.6 million in currency hedging gains.

12. INCOME TAXES

Payments received by the Trust in the form of royalty payments, interest, dividends, distributions or other income from its subsidiaries are taxable income to the Trust. As the Trust is entitled to deduct its cost of acquiring trust royalties, its administrative costs and taxable distributions to Unitholders from its taxable income, the Trust is not expected to be liable for income taxes either currently or in the foreseeable future.

In preparing the 2002 tax return, Canadian Oil Sands found that there was an error in the 2001 Trust tax return prepared by its former tax service provider. In September 2003, the Trust paid $10 million to Canada Revenue Agency ("CRA"), being $9 million for the 2001 tax liability and the balance relating to accrued interest. In 2004, Canadian Oil Sands recovered the $10 million payment from the former tax service provider. The recovery has been recorded as a reduction to income tax expense and net interest expense in Canadian Oil Sands' net income in 2004.

The Trust's most significant operating subsidiary is COSL, which is subject to tax in the same manner as any other corporation. However, as royalty and interest payments made by COSL to the Trust and COSL's affiliates are deductible in computing its taxable income, COSL is not expected to pay significant cash taxes either currently or in the future under existing tax legislation, with the exception of Large Corporations tax, which will be phased out by 2008.

The tax provision recorded on the consolidated financial statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rate to income before tax as follows:

	2004	2003
Income before taxes	**$ 479.9**	$ 325.3
Statutory rates		
Federal	**36.00%**	38.00%
Federal abatement	**–10.00%**	–10.00%
Federal surtax	**1.12%**	1.12%
Alberta provincial rate	**11.54%**	12.62%
	38.66%	41.74%
Expected taxes at statutory rate	**$ 185.5**	$ 135.8
Add (Deduct) the tax effect of:		
Net income of the Trust – tax sheltered	**(181.3)**	(128.4)
Resource allowance	**(18.5)**	(21.0)
Non-deductible Crown charges	**4.3**	3.1
Capital tax	**7.3**	7.8
2001 Reassessment	**(9.3)**	9.3
Tax rate changes	**(9.9)**	12.5
Assessments and adjustments	**(3.6)**	–
Other	**(3.8)**	(3.9)
Provision for taxes	**$ (29.3)**	$ 15.2

Canadian Oil Sands' income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes than for financial statement purposes. The amount shown on the Consolidated Balance Sheet as future income taxes represents the net differences between tax values and book carrying values on the operating subsidiaries' Balance Sheet at substantively enacted tax rates. GAAP requires this future tax liability to be recognized in the consolidated financial statements. These future taxes are not expected to result in cash taxes being paid as a result of expected future intercompany royalty and interest deductions at the operating subsidiary level.

As at December 31, future income taxes are comprised of the following:

	2004	2003
Capital and other assets in excess of tax value	**$ (518.2)**	$ (493.2)
Net liabilities in excess of tax value	**276.3**	224.0
Balance at December 31	**$ (241.9)**	$ (269.2)

As at December 31, 2004, the following are the estimated balances available for deduction against future taxable income:

	2004
Canadian Oil Sands Trust:	
Canadian Development Expense [1]	$ 100.3
Equity Issue Costs	$ 19.8
Canadian Oil Sands Limited and other operating subsidiaries:	
Undepreciated Capital Costs ("UCC") [2]	
Federal UCC	$ 2,361.3
Provincial UCC	$ 2,174.9
Debt Issue Costs	$ 14.7

1 Deductible at a declining balance rate of 30 per cent annually.

2 Majority deductible at a declining balance rate of 25 per cent annually. Approximately $0.9 billion is not available for use until the UE-1 upgrader is put into service.

13. UNITHOLDERS' EQUITY

	2004	2003
Unitholders' capital (a)	$ 1,911.5	$ 1,708.2
Accumulated earnings	1,744.9	1,235.7
Accumulated unitholder distributions	(1,022.2)	(841.8)
Contributed surplus (Note 14 (a))	1.7	0.8
	$ 2,635.9	$ 2,102.9

a) Unitholders' capital

A maximum of 500,000,000 Units have been created for issuance pursuant to the Trust Indenture. The Units represent a beneficial interest in the Trust, share equally in all distributions from the Trust and carry equal voting rights. No conversion or pre-emptive rights, and limited retraction rights are attached to the Units. Units are redeemable at the option of the Unitholder at a price that is the lesser of 90 per cent of the average closing price of the Units on the principal trading market for the previous 10 trading days and the closing market price on the date of tender for redemption, subject to restrictions on the amount to be redeemed each quarter.

On July 30, 2004 the Trust issued three million Units on a private placement basis at a subscription price of $48 per Unit for total proceeds of $144 million, which were used to finance a portion of the Trust's capital expenditures. During 2004, 1.3 million Units were issued for proceeds of approximately $59 million related to the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") with respect to the distributions paid on February 27, 2004, May 31, 2004, August 31, 2004 and November 30, 2004.

In February 2003 the Trust raised $756 million, $732 million net of issue costs, in new equity to finance a significant portion of the $1.05 billion acquisition of the 10 per cent Working Interest in Syncrude from EnCana. The equity issue was comprised of a public offering of 12.3 million Units for gross proceeds of $431 million, and a private placement with a large U.S. institutional investor of 9.4 million Units for gross proceeds of $325 million.

In July 2003, the Trust raised an additional $228 million, $220 million net of issue costs, in new equity to support financing of the $430 million acquisition of the 3.75 per cent Working Interest in Syncrude from EnCana. The equity issue was comprised of a public offering of 5.5 million Units for gross proceeds of $193 million, and a private placement with a large Canadian bank of one million Units for gross proceeds of $35 million.

In 2003, including public and private placement equity offerings and the DRIP, 29.5 million Units with net proceeds of approximately $1 billion were issued. The following table summarizes the Units that have been issued:

Date	Net Proceeds per Unit	Number of Units	Net Proceeds
Balance, January 1, 2003		57.7	$ 708.9
February 28, 2003	$ 33.76	21.8	$ 737.9
May 29, 2003	$ 32.99	0.3	$ 8.9
July 3, 2003	$ 33.82	6.5	$ 219.8
August 29, 2003	$ 35.65	0.4	$ 15.0
November 28, 2003	$ 37.89	0.5	$ 17.7
Balance, December 31, 2003		87.2	$ 1,708.2
February 27, 2004	$ 45.99	0.3	$ 14.1
May 31, 2004	$ 40.59	0.3	$ 11.2
July 30, 2004	$ 48.00	3.0	$ 144.0
August 31, 2004	$ 46.05	0.3	$ 16.9
November 30, 2004	$ 56.57	0.3	$ 17.1
Balance, December 31, 2004		91.4	$ 1,911.5

The Trust has a Unitholder Rights Plan (the "Rights Plan") designed to provide the Trust and its Unitholders with sufficient time to explore and develop alternatives for maximizing Unitholder value if a takeover bid is made for the Trust. One right has been issued and attached to each Unit issued and outstanding. Rights issued under the Rights Plan become exercisable when a person, and any related parties, has acquired or begins a takeover bid to acquire 20 per cent or more of the Units without complying with certain provisions in the Rights Plan. Should such an acquisition or announcement occur, each right entitles the holder other than the acquiring person, to purchase Units at a 50 per cent discount to the market price.

b) Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan

In January 2002, the Trust received regulatory approval in Canada for a DRIP. Eligible Unitholders may participate in the DRIP for the quarterly distributions payable subject to enrolment and certain other conditions. The DRIP allows eligible Unitholders to direct their distributions to the purchase of additional Units at 95 per cent of the Average Market Price as defined in the DRIP. The DRIP also provides an alternative whereby eligible Unitholders may, under the premium distribution component, have their distributions invested in new Units and exchanged through the Plan broker for a premium distribution equal to up to 102 per cent of the amount that the other Unitholders would otherwise have received on the distribution date. Under the terms of the DRIP, Unitholders have the option to purchase additional Units for cash at 100 per cent of the Average Market Price if they have participated in either of the premium distribution or distribution reinvestment components of the DRIP.

c) Net Income Per Unit

The following table summarizes the Units used in calculating net income per Unit:

	2004	2003
Weighted-average Units outstanding – Basic	**89.0**	79.7
Effect of options	**0.1**	–
Weighted-average Units outstanding – Diluted	**89.1**	79.7

14. STOCK-BASED COMPENSATION

In April 2002, the Unitholders of Canadian Oil Sands approved two stock-based compensation plans as described in (a) of this note. Also included in Canadian Oil Sands' consideration of stock-based compensation is the stock-based compensation plan that Syncrude Canada adopted in 2002.

a) Canadian Oil Sands Unit Option and Distribution Equivalent Plan

Canadian Oil Sands has a unit option and distribution equivalent plan pursuant to which a total of 700,000 options were authorized for issuance to employees of Canadian Oil Sands Trust and its subsidiaries. Each option under the plan entitles the employee to purchase a Unit in Canadian Oil Sands Trust at a specified exercise price. The exercise price is based on the weighted-average price of the Units for the five trading days immediately prior to the grant date, which will likely be different than the closing price on the Toronto Stock Exchange for such Units on the day of grant. For options granted in each of 2004 and 2003, the exercise price was not materially different from the trading price of the Units on the grant date. Subject to customary exceptions relating to early retirement, death or termination, each option has a term of seven years. Options vest over a period of three years, commencing from the date of grant. As at December 31, 2004, there were 426,400 options issued and outstanding.

Each option includes a distribution equivalent component, whereby each option holder may, at the discretion of the Board of Directors, receive a distribution equivalent payment for each option held equal to the distributions per Unit paid to Unitholders by the Trust. The Board of Directors utilizes this cash compensation component to reward employees for their contributions to Canadian Oil Sands.

On October 2, 2003, the directors elected to not issue any further options to directors and to instead provide Units, purchased in the secondary market, as part of the directors' annual compensation. Effective October 23, 2003, the directors surrendered all options previously held by them in exchange for Units with a value of approximately $1 million.

As at December 31, 2004, the following options were issued:

Date	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2003	0.3	$ 38.67
Granted in 2003	0.1	$ 39.32
Cancelled in 2003	(0.1)	$ 39.08
Outstanding at December 31, 2003	0.3	$ 38.85
Granted in 2004	0.1	$ 46.64
Outstanding at December 31, 2004	0.4	$ 40.88
Exercisable at December 31, 2003	0.1	$ 38.55
Exercisable at December 31, 2004	0.1	$ 38.74

The range of exercise prices of the options is $34.73 to $46.64 and the average remaining contractual life of the options outstanding is 5.3 years.

The fair value of each option is estimated on the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the various periods and the weighted average assumptions used in their determination are as noted below:

	2004	2003
Risk-free interest rate (%)	**3.63**	4.07
Expected life (years)	**5.00**	5.00
Expected volatility (%)	**20.00**	20.00
Expected distribution per Trust unit ($)	**2.00**	2.00
Fair value per stock option ($)	**6.75**	5.00

The weighted-average fair value of all options granted during the year is approximately $0.7 million (2003 – $0.6 million).

As a result of the retroactive change in accounting policy related to stock-based compensation as explained in Note 3(c), compensation costs of $0.6 million have been included in Administration expenses in Canadian Oil Sands' net income for 2003, with a corresponding increase to contributed surplus included in Unitholders' Equity. Stock-based compensation expense of $0.2 million relating to options granted in 2002 has been charged to opening retained earnings in 2003 with a corresponding increase to contributed surplus.

b) Syncrude Incentive Phantom Share Units Plan

Syncrude Canada implemented a stock-based compensation plan during 2002 which awarded phantom units to certain employees. The phantom units have value if the composite value of the weighted-average stock price of 70 per cent of Canadian Oil Sands Trust's Units and 30 per cent of various other joint venture owners' public shares at the time of exercise by Syncrude Canada employees exceeds the issue price of the awards. The phantom units vest based on a graded vesting schedule: after the first year of issuance, 50 per cent of the phantom units are exercisable, 25 per cent the following year and the last 25 per cent after year three. When the awards are exercised, they are settled in cash. They expire after seven years from the date of issue. At December 31, 2004, a total of 407,928 Syncrude Canada phantom units were exercisable.

At December 31, 2004 a total of 1.3 million phantom units were outstanding (2003 – 1.3 million). In 2004, Canadian Oil Sands recorded approximately $12.1 million in operating expenses related to its 35.49 per cent share of Syncrude Canada's stock-based compensation expense (2003 – $5.1 million, based on Canadian Oil Sands' varying working interests in 2003).

15. INTEREST, NET

		2004		2003
Interest expense	**$**	**98.9**	$	72.0
Interest income and other		**(3.6)**		(4.2)
Interest, net	**$**	**95.3**	$	67.8

16. UNITHOLDER DISTRIBUTIONS

The Consolidated Statements of Unitholder Distributions is provided to assist Unitholders in reconciling funds from operations to Unitholder distributions.

Distributions are paid to Unitholders on the last business day of February, May, August and November.

Consolidated Statements of Unitholder Distributions

For the years ended December 31 ($ millions, except per Unit amounts)	2004	2003
Funds from operations	**$ 575.8**	$ 272.8
Add (Deduct):		
Capital expenditures	**(942.1)**	(785.5)
Non-acquisition financing, net (1)	**549.6**	683.6
Change in non-cash working capital	**1.6**	2.7
Reclamation trust funding	**(4.5)**	(3.7)
Unitholder distributions	**$ 180.4**	$ 169.9
Unitholder distributions per Unit	**$ 2.00**	$ 2.00

(1) Represents financing to fund Canadian Oil Sands' share of Syncrude's Stage 3 expansion and is a discretionary item.

17. DERIVATIVE FINANCIAL INSTRUMENTS

The fair values of financial instruments that are included in the Consolidated Balance Sheet, with the exception of the Senior Notes and medium term notes, approximate their recorded amount due to the short-term nature of those instruments. The fair values of the Senior Notes and medium term notes are as follows:

	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
3.95% medium term notes due January 15, 2007	**$ 175.0**	**$ 176.2**	$ –	$ –
Floating rate medium term notes due January 15, 2007	**20.0**	**20.0**	–	–
7.625% Senior Notes due May 15, 2007	**84.2**	**91.2**	90.4	110.5
5.75% medium term notes due April 9, 2008	**150.0**	**157.8**	150.0	157.1
5.55% medium term notes due June 29, 2009	**200.0**	**209.1**	–	–
4.8% Senior Notes due August 10, 2009	**300.9**	**305.7**	–	–
5.8% Senior Notes due August 15, 2013	**361.1**	**372.9**	387.7	393.1
7.9% Senior Notes due September 1, 2021	**300.9**	**370.7**	323.1	363.8
8.2% Senior Notes due April 1, 2027	**89.0**	**106.4**	95.6	112.7
	$ 1,681.1	**$ 1,810.0**	$ 1,046.8	$ 1,137.2

Canadian Oil Sands has entered into currency exchange contracts, interest rate swap agreements, and forward contracts for crude oil to minimize the impact of fluctuations in currency exchange rates, interest rates, and crude oil prices. Unrecognized gains (losses) on these risk management activities and the fair values of the derivative financial instruments as at December 31 were as follows:

	2004		2003	
	Unrecognized Gains (Losses)	Estimated Fair Value	Unrecognized Gains (Losses)	Estimated Fair Value
Currency exchange contracts (a)	$ 53.5	$ 51.8	$ 49.7	$ 47.5
7.625% Interest rate swap contracts (b)(i)	n/a [1]	3.4	5.4	5.1
3.95% Interest rate swap contracts (b)(ii)	1.5	1.5	–	–
Crude oil hedge contracts (c)	– [2]	–	(68.6)	(68.0)
Total gains (losses)	$ 55.0	$ 56.7	$ (13.5)	$ (15.4)

1 Effective January 1, 2004, pursuant to AcG-13, the 7.625% interest rate swap does not qualify for hedge accounting, and therefore, the fair value of the swap is recognized on the Consolidated Balance Sheet.

2 As at December 31, 2004, there are no crude oil hedge contracts in place.

a) Currency exchange contracts

As at December 31, 2004, Canadian Oil Sands had entered into foreign exchange contracts to sell approximately US$180 million at rates averaging from US$0.664 to US$0.692 over the years 2005 to 2007. As at December 31, 2004, the unrecognized gain on forward foreign currency exchange contracts was $53.5 million (2003 – $49.7 million). In 1996, Canadian Oil Sands entered into currency exchange contracts, fixing the exchange rate on US$1.5 billion at approximately US$0.694 per Canadian dollar with quarterly cash settlements until June 2016. During 1999, Canadian Oil Sands exchanged gains on closing certain forward currency contracts for adjustments to the terms of existing currency contracts. These transactions eliminated currency exchange commitments beyond June 30, 2006, and swapped the underlying value for currency exchange contracts, which reduced the exchange rate to US$0.658 from US$0.694 on the remaining US$466 million of currency commitments.

In 2004, Canadian Oil Sands settled US$92 million of currency exchange contracts at a net gain of $18.7 million, and in 2003, it settled US$88 million in currency exchange contracts at a net gain of $9.0 million. Gains of $13.0 million and $3.6 million in 2004 and 2003, respectively, have been recognized in the income statement as an adjustment to revenues. The remaining portion of these realized gains of $5.7 million and $5.4 million for 2004 and 2003, respectively, relate to the unwound positions and has been deferred. Cumulatively, Canadian Oil Sands has deferred recognition of gains totalling $27.6 million (2003 – $21.9 million) to 2006 and beyond for accounting purposes. The deferred balance is reflected in the Consolidated Balance Sheet under “Deferred currency hedging gains” and is more fully described in Note 11.

The following are the currency hedge positions as of December 31, 2004:

	2005	2006	2007
U.S. dollars hedged ($ millions)	$ 100.0	$ 60.0	$ 20.0
Average U.S. dollar exchange rate	$ 0.664	$ 0.669	$ 0.692

b) Interest rate swap contracts

i) 7.625% Senior Notes

Canadian Oil Sands has entered into interest rate swap agreements which effectively converted the fixed rate U.S. dollar payments on the 7.625% Senior Notes to a 5.95% fixed rate U.S. dollar payment for the remaining term of the notes.

In 2004, Canadian Oil Sands received payments totalling $1.5 million in cash settlements on these interest rate swap agreements, resulting in an effective interest rate on the 7.625% Senior Notes of 6.2%. In 2003 net cash settlements totalling $1.5 million were received, resulting in an effective interest rate of 5.6%. The settlements on these contracts have been recorded as other income, rather than as a reduction of interest expense as these swaps do not qualify as a hedge of the interest expense on the 7.625% Senior Notes for accounting purposes.

ii) 3.95% Medium Term Notes

Canadian Oil Sands has entered into interest rate swap agreements which effectively converted the fixed rate Canadian dollar payments on the 3.95% medium term notes to floating rate Canadian dollar payment for the remaining term of the notes.

In 2004, Canadian Oil Sands received payments totalling $1.0 million in cash settlements on these interest rate swap agreements, resulting in an effective interest rate on the 3.95% medium term notes of 2.9%. These swap contracts qualify as hedges for accounting purposes, and as such, the settlements of these contracts have been recorded as a reduction to interest expense in the financial statements.

c) Crude oil hedging contracts

In 2004, Canadian Oil Sands' revenues were reduced by $274.3 million (2003 – $99.9 million) from crude oil price hedging losses. As of December 31, 2004, there were no crude oil swap positions in place.

d) Natural gas price contracts

Purchased energy costs represent a significant component of Canadian Oil Sands' operating cost. To assist in protecting cash flows associated with changes in natural gas prices, Canadian Oil Sands entered into a forward purchase of 20,000 gigajoules ("GJ") per day of natural gas at an average AECO price of $3.44 per GJ in January 2002. This represented approximately 60 per cent of its share of Syncrude's consumption. The contracts began April 2002 and extended to March 2003. During 2003, natural gas hedging gains of $5.7 million were recorded as a reduction to operating expenses. There were no natural gas hedge contracts in place in 2004, and no contracts have been entered into for years beyond 2004.

e) Credit risk

Crude oil sales revenue credit risk is managed by limiting the exposure to customers with a credit rating below investment grade to a maximum of 25 per cent of Canadian Oil Sands' consolidated accounts receivable. The maximum exposure to any one customer is also limited based on the credit rating of that customer. Risk is further mitigated as sales revenue receivables are due and settled in the month following the sale. The use of financial instruments involves a degree of credit risk which Canadian Oil Sands manages through its credit policies and by selecting counterparties of high credit quality.

18. CROWN ROYALTIES

The Alberta Crown Agreement created a Joint Venture (the Alberta Joint Venture) between the Province of Alberta as lessor and the Syncrude participants as lessees. Its purpose was to annually establish, using a deemed net profit concept, the basis on which Syncrude's annual production is to be shared by the lessor and each of the lessees.

Beginning in 2002, the Alberta Crown royalty agreement was replaced with Alberta's generic Oil Sands Royalty. Under this regime, the Crown royalty is calculated as the greater of one per cent of gross revenue after transportation costs or 25 per cent of revenue before hedging, less applicable transportation, operating, non-production and capital costs. In each of 2004 and 2003, the Crown royalty was calculated at one per cent of gross revenue. As Syncrude is in a significant capital program, Canadian Oil Sands expects to pay only the minimum one per cent royalty on its gross revenues in 2005 based on its pricing and production forecast at December 31, 2004. As at December 31, 2004, carry forward deductions for royalty purposes were approximately $1.5 billion, $0.5 billion net to Canadian Oil Sands.

19. COMMITMENTS AND CONTINGENCIES

a) Marketing agreement

Under the terms of the Marketing Services Agreement between COSL and EnCana, EnCana markets all of the production attributable to Canadian Oil Sands' Working Interest for a fee of $0.05 per barrel, with a minimum monthly fee of $33,333. The marketing fees are included in Canadian Oil Sands' transportation and marketing expense on the Consolidated Statement of Income and Unitholders' Equity. The agreement expires on June 30, 2006, unless it is extended.

b) Natural gas purchase commitments

Syncrude has entered into purchase commitments for natural gas deliveries in 2005 at market–related prices. Canadian Oil Sands' 35.49 per cent share of this commitment is for 13.9 million GJ, which based on NYMEX natural gas future prices, amounts to approximately $84.5 million.

c) Expenditure commitments

The total estimated project cost of Syncrude's Stage 3 expansion is $7.8 billion, or approximately $2.8 billion net to Canadian Oil Sands, with completion estimated for mid-2006. Based on expenditures incurred on the Stage 3 project to December 31, 2004, Canadian Oil Sands' 35.49 per cent share of the remaining expenditures is approximately $0.5 billion. Canadian Oil Sands is also committed to remaining costs of approximately $0.3 billion related to its 35.49 per cent share of Syncrude's emissions reduction program and additional mining systems at the Aurora North and North Mine to replace production from a portion of the Base Mine that we anticipate will be depleted in 2006.

d) Desulphurization unit

Syncrude has entered into an agreement with Marsulex Inc. to utilize flue gas from Coker 8-3 of Stage 3 to make fertilizer. Under the agreement, which begins in 2005 and has a minimum term of 15 years, Syncrude is committed to provide the waste stream from the Flue Gas Desulphurization Unit and pay an annual disposal fee. Syncrude receives a portion of the proceeds from the fertilizer sales as a cost recovery. Canadian Oil Sands' share of this commitment, before any recovery, is approximately $3 million per year.

e) Tax assessment

CRA has reassessed and settled the tax years prior to 2000 of COSL's predecessors, Canadian Oil Sands Investments Inc. ("COSII") and Athabasca Oil Sands Investments Inc. ("AOSII"), pertaining to the Syncrude Remission Order ("SRO") and other tax issues. CRA is still reviewing the SRO and other tax issues in respect of both companies for the years 2000 to 2002. AOSII has filed a Notice of Objection in respect of taxes owing and refunds related to the SRO for years pertaining to 2000 to 2002. There have been no other Notices of Objection filed in respect of AOSII for the years 2000 to 2002 as CRA has not yet issued any reassessments for those years. The timing of when all of the assessments will be resolved and the impact on the tax pool balances was not determinable at December 31, 2004.

f) Pipeline commitments

Canadian Oil Sands has a long-term agreement with Athabasca Oil Sands Pipeline Limited ("AOSPL") to transport production from the Syncrude plant gate to Edmonton, Alberta, Canada. The agreement provides for reimbursement on a cost of service basis, including operating expenses, cash taxes paid, and a return on the depreciated rate base. The agreement commits Canadian Oil Sands to pay its proportionate share of the cost of service whether or not it ships any production on the pipeline. The cost of service in 2004, based on Canadian Oil Sands' 35.49 per cent working interest, was $18.8 million (2003 – $15.3 million, based on varying working interests during the year). The projected cost of service for 2005 is $21 million, based on Canadian Oil Sands' 35.49 per cent Working Interest at December 31, 2004, and is expected to remain around this level through 2008.

g) General

Various suits and claims arising in the ordinary course of business are pending against Syncrude Canada, the operator of the Syncrude project for the participants. While the ultimate effect of such actions cannot be ascertained at this time, in the opinion of the Trust's management, the liabilities which could reasonably be expected to arise from such actions would not be significant in relation to the operations of Syncrude. Syncrude Canada as well as Canadian Oil Sands and the other Syncrude Joint Venture owners also have claims pending against various parties, the outcomes of which are not yet determinable.

20. GUARANTEES

Canadian Oil Sands has posted performance standby letters of credit with the Province of Alberta which are renewed annually. The letters of credit guarantee to the Province of Alberta the reclamation obligations of Canadian Oil Sands' interest in future reclamation of the Syncrude mine sites. The Province of Alberta can draw on the letters of credit if Syncrude fails to perform its reclamation duties on its mine sites. The maximum potential amount of payments Canadian Oil Sands may be liable for pursuant to these letters of credit is $38 million. Canadian Oil Sands accrues an asset retirement obligation (Note 10) on its Consolidated Balance Sheet for its share of Syncrude's reclamation costs, which was $44.1 million at December 31, 2004.

21. SUPPLEMENTARY INFORMATION

a) Change in non-cash working capital

	2004	2003
Operating activities		
Accounts receivable	**$ (29.5)**	$ 31.0
Inventories	**0.3**	(14.6)
Prepaid expenses	**1.7**	(0.1)
Accounts payable and accrued liabilities	**45.4**	(67.3)
	17.9	(51.0)
Financing activities		
Unit distribution payable	**$ 2.1**	$ 14.7
Investing activities		
Accounts payable and accrued liabilities	**$ (18.4)**	$ 39.0

22. RECLASSIFICATION

Certain prior year's figures have been reclassified to conform to the presentation adopted for 2004.

STATISTICAL SUMMARY

($ millions, except as indicated)	2004	2003	2002	2001	2000	1999	1998
Revenues, after transportation and marketing expense	**1,352**	932	715	663	665	468	329
Operating costs	**601**	515	309	327	276	216	219
Non-production costs	**48**	38	19	18	7	6	6
Crown royalties	**18**	12	7	53	125	9	–
Administration	**9**	9	7	8	9	8	4
Insurance	**9**	7	6	4	2	2	2
Interest, net	**95**	68	39	20	13	11	13
Depreciation, depletion and accretion	**172**	93	54	59	54	64	56
Foreign exchange loss (gain)	**(80)**	(135)	(3)	24	6	(11)	14
Income and Large Corporations Tax	**(2)**	17	6	2	2	1	1
Future income tax recovery	**(27)**	(2)	–	–	–	–	–
Dividends on preferred shares of subsidiaries	**–**	–	–	–	1	1	1
Net income	**509**	310	271	148	170	161	13
Per Trust unit ($)	**5.72**	3.89	4.74	2.61	3.00	2.84	0.24
Funds from operations	**576**	273	326	227	233	206	81
Per Trust unit ($)	**6.47**	3.43	5.71	4.00	4.10	3.64	1.51
Unitholder distributions	**180**	170	115	156	133	72	19
Per Trust unit ($)	**2.00**	2.00	2.00	2.75	2.34	1.27	0.35
Capital expenditures	**942**	786	403	180	110	163	108
Reserves (MMbbls, net to COS)							
Proven reserves	**1,040**	1,070	676	694	713	598	597
Proven and probable reserves	**1,815**	1,810	N/A	N/A	N/A	N/A	N/A
Resource (includes proven and probable reserves)	**3,192**	3,240	1,794	1,808	1,831	1,830	1,847
Average daily sales (bbls)	**84,575**	66,793	49,806	48,508	44,145	48,456	45,497
Operating netback ($/bbl)							
Average realized sales price	**43.68**	38.23	39.35	37.46	41.15	26.50	19.93
Operating costs	**19.40**	21.12	16.99	18.48	17.14	12.22	13.21
Crown royalties	**0.58**	0.49	0.41	2.97	7.75	0.54	0.01
Netback price	**23.70**	16.62	21.95	16.01	16.26	13.74	6.71
Financial ratios							
Net debt to cash flow (times)	**2.9**	5.2	1.2	1.2	0.5	0.5	1.9
Net debt to total capitalization (%)	**39.0**	40.3	29.0	25.8	11.9	10.7	18.5
Return on average Unitholders' equity (%)	**21.4**	20.2	31.3	18.4	20.9	21.9	2.1
Number of Trust units outstanding (in millions)	**91.4**	87.2	57.7	56.8	56.8	56.8	54.0
$/Unit prices*							
High	**68.19**	45.70	44.85	41.95	33.00	25.90	24.50
Low	**40.25**	32.26	33.28	29.25	23.50	16.90	14.00
Close	**67.61**	45.69	38.05	38.50	29.10	24.90	16.80
Annual trading volume (thousands of Trust units)*	**77,832**	45,417	33,296	20,360	12,673	8,657	9,657

* Data prior to the July 5, 2001, merger date represent Athabasca Oil Sands Trust, the surviving entity.

GLOSSARY

Bitumen
The molasses-like substance that comprises up to 18% of oil sands. Bitumen, in its raw state, is black, asphalt-like oil – and it requires upgrading to make it transportable by pipeline and usable by conventional refineries.

Carbon dioxide (CO_2)
A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities.

Cokers
Vessels in which bitumen is cracked into its fractions and from which coke is withdrawn to start the process of converting bitumen to upgraded crude oil.

Conventional oil
Petroleum found in liquid form, flowing naturally, or capable of being pumped without further processing or dilution.

Debottleneck
Debottlenecking systematically removes plant capacity limitations through modifications of existing facilities and/or addition of capital facilities. Debottlenecking commonly provides a modest (10-20%) capacity improvement versus a major capital intensive expansion.

Dragline
A large machine that digs oil sand from the mine pit and piles it into windrows.

Extraction
The process of separating bitumen from oil sand.

Flue gas scrubber
Equipment that removes sulphur dioxide and other emissions from a coker.

Fluid coking
A major part of the upgrading process whereby high temperatures in a coker remove carbon and cause bitumen molecules to reformulate into lighter products that become the main ingredients in upgraded crude oil.

Greenhouse gases
Any of various gases that contribute to the greenhouse effect.

Gross overriding royalty (GORR)
Six percent gross overriding royalty on revenues from the working interest in respect of certain leases included in the Syncrude project.

Oil sand(s)
A composition of sand, bitumen, mineral rich clays and water.

Alberta oil sand(s) deposits
The four deposits, Athabasca, Peace River, Cold Lake and Wabasca, have total resource in place estimated at 1.7 trillion to 2.5 trillion barrels. The Athabasca Oil Sands deposit, Alberta's largest and most accessible source of bitumen, contains more than one trillion barrels of bitumen over an area encompassing more than 30,000 square kilometres.

Oil sand(s) lease
A long-term agreement with the provincial government which permits the leaseholder to extract bitumen, other metals and minerals contained in the oil sands in the specified lease area.

Overburden
A layer of rocky, clay-like material beneath muskeg.

Sulphur dioxide (SO_2)
A compound of sulphur and oxygen produced by burning sulphur.

Syncrude 21
In 1996, Syncrude embarked on a 5-stage expansion plan, which is anticipated to more than double production of a higher-quality oil at lower operating costs.

Syncrude Sweet Blend (SSB)
A 100% upgraded, high-quality product with 31° to 33° API, low sulphur (0.1% to 0.2%), low residuals and excellent low-temperature pour qualities.

Syncrude Sweet Premium (SSP)
A new product that is expected to be introduced with the startup of Syncrude's UE-1 expansion project; the quality of the distillate cuts will improve significantly with lower sulphur and nitrogen levels as well as higher diesel cetane numbers and kerosene smoke points.

Synthetic crude oil
A high-quality product resulting from the mining, extraction and upgrading of thick, tar-like bitumen.

Tailings
A combination of water, sand, silt and fine clay particles that is a by-product of removing bitumen from oil sand.

Turnaround
A regular event essential for good maintenance of the mining, producing and upgrading facilities. A turnaround(s) may reduce SSB production but does not usually halt it entirely as the various operating units are duplicated.

Upgrading
The conversion of heavy bitumen into a lighter crude oil by increasing the ratio of hydrogen to carbon, either by removing carbon (coking) or adding hydrogen (hydroprocessing).

Abbreviations

barrel(s)	bbl, bbls
barrel(s)/day	bbl/d, bbls/d
millions of barrels	MMbbls
carbon dioxide	CO_2
New York Mercantile Exchange	NYMEX
sulphur dioxide	SO_2
Syncrude Sweet Blend	SSB
Syncrude Sweet Premium	SSP
West Texas Intermediate	WTI

INVESTOR INFORMATION

Officers

C. E. (Chuck) Shultz
Chairman of the Board

Marcel R. Coutu
President and Chief Executive Officer

Allen R. Hagerman, F.C.A.
Chief Financial Officer

Trudy M. Curran
General Counsel and Corporate Secretary

Ryan M. Kubik
Treasurer

Laureen C. DuBois
Controller

Board of Directors

C. E. (Chuck) Shultz [2]
(Chairman of the Board)
Chairman and Chief Executive Officer
Dauntless Energy Inc.
Calgary, Alberta

Marcel R. Coutu
President and Chief Executive Officer
Canadian Oil Sands Trust

E. Susan Evans, Q.C. [1, 2]
Calgary, Alberta

The Honourable Donald F. Mazankowski [1]
Vegreville, Alberta

Wayne M. Newhouse [2]
President, Morgas Ltd.
Calgary, Alberta

Walter B. O'Donoghue, Q.C. [1]
Counsel, Bennett Jones LLP
Calgary, Alberta

Wesley R. Twiss [2]
Calgary, Alberta

John B. Zaozirny, Q.C. [1]
Counsel, McCarthy Tétrault LLP
Calgary, Alberta

1 Member of the Corporate Governance and Compensation Committee
2 Member of the Audit Committee

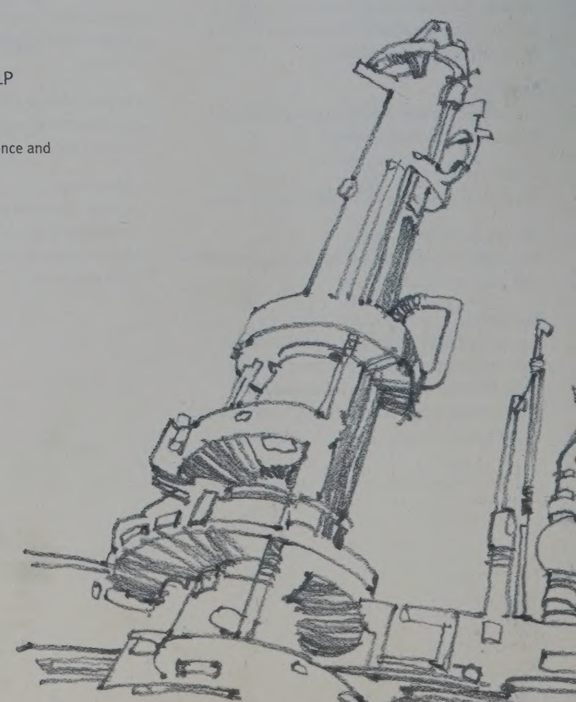
Units Listed

The Toronto Stock Exchange: COS.UN

Registrar and Transfer Agent

Computershare Trust Company of Canada, with offices in Vancouver, Calgary, Toronto, Montreal and Halifax, is the registrar and Transfer Agent for Canadian Oil Sands Trust. Computershare is also Trustee of the Trust.

Computershare Trust Company of Canada
710, 530 – 8th Avenue SW
Calgary, Alberta, T2P 3S8
Attention: Corporate Trust Department
Telephone: 1 (800) 564-6253
Fax: (403) 267-6598
E-mail: service@computershare.com



Auditors
PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

Annual and Special Meeting
The Annual and Special Meeting of Unitholders will take place in the Chambers Room of First Canadian Centre, 350 – 7th Avenue SW, Calgary, Alberta, on Monday, April 25, 2005, at 2:30 p.m.

Canadian Oil Sands Limited
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350 – 7th Avenue SW
Calgary, Alberta, T2P 3N9
Telephone: (403) 218-6200
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Investor and Media Relations Contact
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Telephone: (403) 218-6228
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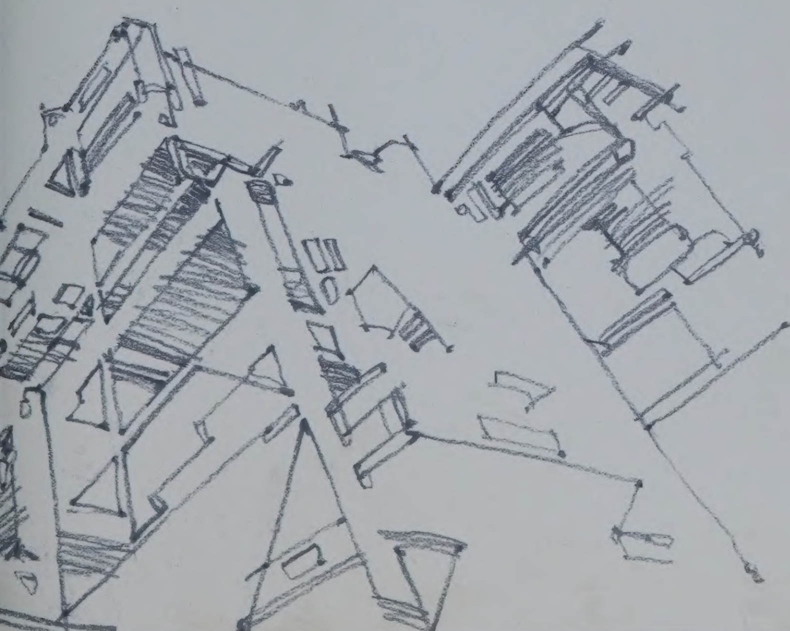
E-mail: investor_relations@cos-trust.com

Website: www.cos-trust.com
Canadian Oil Sands' website contains a variety of investor information including:
- Current Unit Price
- Annual and Interim Reports
- News Releases
- Investor Presentations
- Distribution Information
- Syncrude Project Information
- Tax Information

DRIP
For more information on, or to enroll in the Trust's Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP"), please contact investor relations at (403) 218-6220 or Computershare Trust Company of Canada at 1 (800) 564-6253.



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Web Site: www.cos-trust.com

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